[JOINT COMMITTEE PRINT]

GENERAL EXPLANATION

OF THE

CRUDE OIL WINDFALL PROFIT TAX ACT OF 1980

(H.R. 3919, 96TH CONGRESS; PUBLIC LAW 96–223)

PREPARED BY THE STAFF OF THE

JOINT COMMITTEE ON TAXATION

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INTRODUCTION

While committee reports explain the position of the House Committee on Ways and Means or the position of the Senate Committee on Finance, they do not always explain the tax legislation that finally is passed by Congress. This is particularly important when the final version of the bill differs significantly from the versions reported by the tax-writing committees.

This document represents the effort of the staff of the Joint Committee on Taxation to provide an explanation of the Crude Oil Windfall Profit Tax Act of 1980 as finally enacted. It is comparable to a number of similar documents prepared by the staff on other revenue acts in recent years. For the most part, where provisions which were unchanged on the House or Senate floor or in conference were described in either the House or Senate committee report, that explanation is used in this document. No attempt is made here to carry the explanation further than is customary in committee reports.

The first part of the document contains a summary of the legislative history of the Act. The second part is a brief summary of the Act. The third part outlines the overall reasons why Congress enacted the legislation. The fourth part contains the budget effects of the Act as they were estimated when the conference report was filed. The fifth part is a general explanation of the provisions.

This material has been prepared by the staff of the Joint Committee on Taxation after the passage of the Crude Oil Windfall Profit Tax Act of 1980. It has not been reviewed by the tax committees and therefore only reflects the staff's view as to the intent of Congress. It is hoped that this document will be useful in gaining a better understanding of the Crude Oil Windfall Profit Tax Act of 1980.

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I. LEGISLATIVE HISTORY OF THE CRUDE OIL WINDFALL PROFIT TAX ACT OF 1980

The following is a chronology of the legislative history of the Crude Oil Windfall Profit Tax Act of 1980 (H.R. 3919, Public Law 96–223).

—***Introduction of H.R. 3919***—May 3, 1979.

—***House Committee on Ways and Means hearings on H.R. 3919***—May 9–11, 16–18, 1979.

—***House Committee on Ways and Means markup on H.R. 3919***—June 7, 11–14, and 19, 1979.

—***H.R. 3919 with amendments reported by House Committee on Ways and Means***—June 22, 1979 (House Report 96–304).

—***House Committee on Rules***—Reported on June 26, 1979 (House Resolution 336).

—***House of Representatives floor action***—Considered and passed with a floor amendment on June 28, 1979.

—***H.R. 3919 referred to Senate Committee on Finance***—July 10, 1979.

—***Senate Committee on Finance hearings***—July 10–12, 18–19, and 31, 1979.

—***Senate Committee on Finance markup***—August 1–2, September 6, 11–12, 18–21, 25–28, October 2–5, 9–12, 16–19, and 25, 1979.

—***H.R. 3919 with amendments reported by Senate Committee on Finance***—November 1, 1979 (Senate Report 96–394).

—***Senate floor action***—November 15–16, 19–20, 26–30, December 3–7, 10–15, and 17, 1979.

—***House-Senate conference on H.R. 3919***—December 19–21, 1979, and January 17, 21–25, February 6–7, 19–22, and 26–27, 1980.

—***Conference report on H.R. 3919***—Filed on March 7, 1980 (House Report 96–817).

—***House Committee on Rules action on conference report***—March 11–12, 1980 (House Resolution 605).

—***House agreed to conference report***—March 13, 1980.

—***Senate considered conference report***—March 19–21, 24–27, 1980.

—***Senate agreed to conference report***—March 27, 1980.

—***H.R. 3919 signed by the President***—April 2, 1980 (Public Law 96–223).

II. SUMMARY OF THE ACT

The Crude Oil Windfall Profit Tax Act of 1980 consists of four titles. Title I imposes a windfall profit tax on domestically produced crude oil. Title II expands the tax credits to encourage residential energy conservation which were enacted in the Energy Tax Act of 1978 and provides tax incentives for businesses to encourage energy conservation and production of alternative energy sources. Title III authorizes energy assistance to low-income persons. Title IV contains several income tax changes, including a partial exclusion for interest and dividend income, certain changes related to LIFO inventories, and repeal of carryover basis. Title IV also imposes restrictions on the President's authority to control oil imports.

Windfall Profit Tax

The windfall profit tax is an excise, or severance, tax on domestically produced crude oil. Taxable oil is taxed in one of three tiers. Tier one consists essentially of oil which would have been lower or upper tier oil had previous price controls been continued. Tier two consists of oil which is stripper oil or production owned by the United States from a National Petroleum Reserve. Tier three consists of newly discovered oil, certain heavy oil, and incremental tertiary oil.

For each tier, the taxable windfall profit is the difference between the selling price of the oil and the sum of the adjusted base price and an adjustment for the State severance tax on the windfall profit.

The base price for tier one oil is the May 1979 upper tier ceiling price for that oil, less $0.21. These tier one base prices will average $12.81 per barrel. The base price for a barrel of tier two oil of national average quality and location is $15.20, and that for a barrel of tier three oil of national average quality and location will be $16.55. All base prices are adjusted for inflation. The tier two and tier three base prices are adjusted for quality and location differentials. A "kicker" of 2 percent per year applies to the inflation adjustment to the tier three base price.

The tax rate applied to the windfall profit is 70 percent for tier one, 60 percent for tier two, and 30 percent for tier three. Independent producers are allowed reduced rates on up to 1,000 barrels a day of their combined production of tier one and tier two oil. For tier one oil the reduced rate is 50 percent, and for tier two oil the reduced rate is 30 percent.

State and local governments, certain charitable medical facilities and educational institutions, and Indian tribes and Indians over whom the United States exercises trust responsibilities are exempt from the tax. There are also exemptions for new oil produced in most of Alaska and for front-end tertiary oil.

The entire windfall profit tax will phase out over a 33-month period after December 31, 1987, or when cumulative net revenues raised

by the tax reach $227.3 billion, whichever is later. However, the phase-out will begin no later than January 1991.

The tax applies to oil removed from the premises after February 29, 1980.

Assuming a price of uncontrolled oil of $30 in the fourth quarter of 1979, and price increases 2 percent above the inflation rate, the tax is expected to raise $227.7 billion between 1980 and 1990.

The revenues raised by the windfall profit tax, up to the amount currently expected ($227.7 billion between 1980 and 1990), are to be allocated as follows:

	Percent
Income tax reductions	60
Low-income assistance	25
Energy and transportation programs	15

Any windfall tax revenues in excess of those currently expected would be allocated two-thirds for tax cuts and one-third for low-income assistance.

Residential Energy Tax Credits

The Act increases the existing tax credit for residential renewable energy property to 40 percent of the first $10,000 of expenditures and makes additional kinds of property eligible for that credit. It also adds specific standards which the Secretary of the Treasury will use when exercising his authority to add items to the list of property eligible for the home insulation tax credit and to add new energy sources to the list of those for which equipment is eligible for the renewable energy source (solar) tax credit.

Business Energy Tax Incentives

The principal business energy tax incentives in the Act are:

(1) An increase to 15 percent and extension through 1985 for the energy investment credit for solar, wind and geothermal equipment, as well as extension of the solar credit to equipment used to provide process heat.

(2) A 15-percent energy credit for certain ocean thermal equipment.

(3) An 11-percent energy credit for small-scale hydroelectric equipment.

(4) A 10-percent energy credit for cogeneration equipment not fueled by oil or gas.

(5) Specific standards which the Secretary of the Treasury will use in exercising his authority to add items to the list of property eligible for the energy credit for "specially defined" energy property.

(6) Restoration of the regular investment credit and accelerated depreciation for boilers using petroleum coke and pitch.

(7) A 10-percent energy credit for coke ovens.

(8) Extension through 1985 of the energy credit for certain biomass and gasohol equipment.

(9) A 10-percent energy credit for certain intercity buses.

(10) A transition rule for energy credits expiring in 1982 to allow those credits through 1990 when affirmative commitments have been made.

(11) A $3 per barrel credit for the production of various alternative energy sources.

(12) Extension through 1992 of the excise tax exemption for gasohol, along with various other tax incentives for gasohol.

(13) Tax exemption for interest on industrial development bonds used to finance small-scale hydroelectric equipment, certain solid waste disposal facilities, and certain renewable energy programs.

(14) Expensing of injectants used in tertiary oil recovery.

Low-Income Energy Assistance

The Act authorizes $3.115 billion for fiscal year 1981 for a program of block grants to the States to provide assistance to lower-income families for heating and cooling costs.

For fiscal year 1982 and subsequent years, the 25 percent of the windfall profit tax revenues allocated for low-income assistance, as specified above, is to be divided equally between a program to assist AFDC and SSI recipients under the Social Security Act and a program of emergency energy assistance.

Other Income Tax Provisions

Other income tax provisions in the Act include:

(1) Repeal of carryover basis.

(2) A $200 exclusion for interest and dividends ($400 for married couples) for 1981 and 1982.

(3) Changes to LIFO inventory accounting rules.

Oil Imports

The Act denies the President the authority to impose oil import quotas if Congress passes a joint resolution disapproving such a quota. The resolution could be vetoed, but the veto could be overridden by a two-thirds vote of both Houses.

III. GENERAL REASONS FOR THE ACT

Congress determined that the Crude Oil Windfall Profit Tax Act of 1980 was needed because of the Administration's decision to phase out price controls on crude oil, the recent increases in world oil prices, and the nation's continuing overdependence on imported energy. The Act was intended to tax a fair share of the additional revenues received by oil producers and royalty owners as a result of oil price decontrol without adversely affecting incentives to produce domestic oil. The Act also includes tax incentives to encourage energy conservation and production of alternate energy sources and assistance to lower-income households to help them cope with higher energy prices.

Oil Price Decontrol

In April 1979, the Administration announced its intention to use its discretionary authority over oil prices to phase out price controls between June 1, 1979, and September 30, 1981, when the existing price control authority expires. Since then, the Department of Energy has issued final regulations on the decontrol program. This program involved the immediate decontrol of newly discovered oil (oil produced from a property which had no production in 1978), the gradual merger of the lower tier of price controls (oil discovered before 1973) with the upper tier (oil discovered between 1972 and 1979), and the phaseout of price controls on oil in the upper tier.

Oil price decontrol and additional oil price increases since early 1979 are causing a significant increase in revenues received by oil producers and royalty owners. In May 1979, just prior to the start of the phased decontrol program, lower tier oil (one-third of domestic production) was controlled at an average price of $5.91 per barrel and non-Alaskan upper tier oil (also one-third of domestic production) was controlled at an average price of $13.02 per barrel. In March 1980, when Congress passed the Act, the average price of uncontrolled oil, to which lower and upper tier oil will rise as controls are phased out, exceeded $35 per barrel.

Congress believed that the large price increases resulting from phased decontrol and extraordinary increases in world oil prices were an appropriate object of taxation. However, it believed that any such tax should be structured carefully to eliminate, as much as possible, adverse effects on domestic production. For this reason, the Act contains lower tax rates for those types of oil whose production Congress believed to be especially responsive to more lenient tax treatment, such as newly discovered oil, tertiary oil, stripper oil and heavy oil. Because of the significant contribution made by independent producers, the Act contains reduced tax rates for up to 1,000 barrels per day of tier one and tier two production by independent producers.

Burden of Higher Energy Prices

The recent increases in energy prices have imposed severe burdens on lower-income households. The price of heating oil, for example, rose from 50 cents a gallon in 1978 to $1.00 in 1980. Heating a home with 1,200 gallons of oil, therefore, would cost $1,200, a significant burden for a low-income person. Natural gas prices, although lower than heating oil prices, have also risen sharply in recent years. The increased cost of propane has adversely affected the living standard of many rural families.

Congress believed that a fair sharing of the costs of higher energy prices requires that part of the tax on oil producers and royalty owners be used to finance assistance to low-income families. The Act includes programs to provide such assistance.

Energy Tax Incentives

A very important part of the Act is a program of tax incentives designed to encourage oil and gas conservation and domestic production.

Many methods of energy conservation and of production of alternate energy sources require new and advanced technologies. Investments are often too risky to be undertaken without some federal assistance, and the initial investors in these projects create benefits for the whole economy by generating information on how to develop and implement the needed new technologies. In many cases, a tax incentive is the most efficient way of providing the necessary aid because it dispenses with the need for a cumbersome bureaucracy to administer a spending or regulatory program.

For these reasons, the Act provides tax incentives for use of a wide range of alternate sources of energy—solar, wind, geothermal, wood, biomass, hydroelectric, ocean thermal, oil shale, tar sands, coal liquefaction and gasification and unconventional natural gas. There are also tax incentives to encourage energy conservation both by businesses and by homeowners.

IV. BUDGET EFFECTS

Table 1 summarizes the estimated revenue effect of the Act for calendar years 1979 to 1990. In 1981, the windfall profit tax was expected to increase tax liabilities by $14.7 billion, and the various tax reductions in the bill to reduce revenues by $2.5 billion. The overall revenue tax gain, then, was expected to be $12.2 billion. Over the entire 12-year period 1979 to 1990, the tax will raise $227.7 billion, and the tax reductions will be $15.5 billion, for a net revenue gain of $212.2 billion.

Table 2 summarizes the revenue effects of the Act for fiscal years 1980 to 1990. In fiscal year 1981, the windfall profit tax raises $13.4 billion, and the tax reductions will be $0.5 billion. Thus, the net tax increase in fiscal year 1981 will be $12.9 billion.

These revenue estimates assume that the price of uncontrolled oil was $30 per barrel in the fourth quarter of 1979 and grows at the rate of inflation plus two percent per year. They are identical to those presented to Congress in the Statement of Managers which accompained the conference report on the Act. Developments since then may have changed the revenue impact of the provisions.

Tables 3 and 4 present the gross and net revenues raised by the windfall profit tax for calendar years 1980–90 and fiscal years 1980–90, respectively. The gross windfall profit tax is the actual receipts from the tax itself. However, the imposition of the tax affects corporate and individual income tax receipts because it is deductible, because it reduces deductible State income taxes, and because it affects oil drilling (the cost of which may be deductible currently for income tax purposes). The net windfall profit tax is the gross windfall profit tax minus the reduction in corporate and individual income taxes expected to result from imposition of the windfall profit tax.

Tables 5 and 6 show the revenue effects of the residential energy tax credits for calendar and fiscal years 1980–90, respectively.

Tables 7 and 8 show the revenue effects of the various business tax incentives for calendar and fiscal years 1980–90, respectively.

Up to $3.115 billion is authorized to be appropriated in fiscal year 1981 for the low-income energy assistance program contained in the Act.

Table 1.—Summary of Estimated Revenue Effects of the Crude Oil Windfall Profit Tax Act of 1980, Calendar Years 1979–90

[In millions of dollars]

Item	Calendar year liabilities						
	1979	1980	1981	1982	1983	1984	1985
Net gain from windfall profit tax	36 [1]	6,306	14,719	18,875	20,147	21,312	22,267
Residential energy tax credits		−42	−53	−69	−97	−138	−201
Business energy tax incentives	−3	−146	−232	−329	−864	−1,182	−1,541
Repeal carryover basis		[2]	−36	−95	−163	−238	−330
Interest and dividend exclusion			−2,095	−2,210			
Involuntary liquidation of LIFO inventories [4]			−85	−85	−80		
Taxing inventory profits at corporate liquidations [5]				250	250	250	250
Total	**33**	**6,118**	**12,218**	**16,337**	**19,193**	**20,004**	**20,445**

Table 1.—Summary of Estimated Revenue Effects of the Crude Oil Windfall Profit Tax Act of 1980, Calendar Years 1979–90— Continued

[In millions of dollars]

Item	Calendar year liabilities					Total 1979–90
	1986	1987	1988	1989	1990	
Net gain from windfall profit tax	22, 907	23, 778	24, 588	25, 771	27, 017	227, 723
Residential energy tax credits						−600
Business energy tax incentives	−824	−887	−1, 044	−626	−616	−8, 297 [3]
Repeal carryover basis	−440	−560	−680	−810	−950	−4, 302
Interest and dividend exclusion						−4, 305
Involuntary liquidation of LIFO inventories [4]						−250
Taxing inventory profits at corporate liquidation [5]	250	250	250	250	250	2, 250
Total	**21, 893**	**22, 581**	**23, 114**	**24, 585**	**25, 701**	**212, 219** [3]

[1] The Act is expected to raise a small amount of income tax revenue in 1979 because the estimates assume that the tax on newly discovered oil reduces intangible drilling deductions in that year.

[2] Less than $1 million.

[3] This total includes $3 million in calendar year 1978 reductions.

[4] These estimates were based on the assumption that the Secretary will invoke this provision for disruptions of oil shipments during 1980.

[5] These estimates are based on information obtained from a selected number of cases known to the Treasury and the figures are intended to provide representative averages during the forecast period.

Table 2.—Summary of Estimated Revenue Effects of the Crude Oil Windfall Profit Tax Act of 1980, Fiscal Years 1980–90

[In millions of dollars]

Item	Fiscal year receipts					
	1980	1981	1982	1983	1984	1985
Net gain from windfall profit tax	3, 172	13, 436	19, 543	19, 958	21, 144	22, 227
Residential energy tax credits	−7	−44	−55	−74	−105	−148
Business energy tax incentives	−50	−206	−274	−567	−985	−1, 426
Repeal carryover basis		(1)	−36	−95	−163	−238
Interest and dividend exclusion		−314	−2, 278	−1, 713		
Involuntary liquidation of LIFO inventories[2]			−85	−85	−80	
Taxing inventory profits at corporate liquidations[3]			112	250	250	250
Total	**3, 115**	**12, 872**	**16, 927**	**17, 674**	**20, 061**	**20, 665**

Table 2.—Summary of Estimated Revenue Effects of the Crude Oil Windfall Profit Tax Act of 1980, Fiscal Years 1980–90—Continued

[In millions of dollars]

Item	Fiscal year receipts					Total 1980–90
	1986	1987	1988	1989	1990	
Net gain from windfall profit tax	22, 776	23, 601	24, 423	25, 593	26, 772	222, 646
Residential energy tax credits	−167					−600
Business energy tax incentives	−1, 233	−866	−972	−870	−637	−8, 086
Repeal carryover basis	−330	−440	−560	−680	−810	−3, 352
Interest and dividend exclusion						−4, 305
Involuntary liquidation of LIFO inventories [2]						−250
Taxing inventory profits at corporate liquidations [3]	250	250	250	250	250	2, 112
Total	**21, 296**	**22, 545**	**23, 141**	**24, 293**	**25, 575**	**208, 165**

[1] Less than $1 million.

[2] These estimates were based on the assumption that the Secretary will invoke this provision for disruptions of oil shipments during 1980.

[3] These estimates are based on information obtained from a selected number of cases known to the Treasury and the figures are intended to provide representative averages during the forecast period.

Note: Details may not add to totals because of rounding.

Table 3.—Estimated Revenue Effect of the Crude Oil Windfall Profit Tax, Calendar Years 1980–90

[In millions of dollars]

Item	Calendar year liabilities					
	1980	1981	1982	1983	1984	1985
Gross windfall profit tax	10, 876	25, 952	33, 534	35, 952	38, 202	40, 104
Change in income taxes	—4, 570	—11, 234	—14, 659	—15, 805	—16, 890	—17, 837
Net windfall profit tax	**6, 306**	**14, 719**	**18, 875**	**20, 147**	**21, 312**	**22, 267**

Item	Calendar year liabilities					
	1986	1987	1988	1989	1990	Total 1980–90 [1]
Gross windfall profit tax	41, 445	43, 185	44, 789	47, 049	49, 399	410, 486
Change in income taxes	—18, 538	—19, 407	—20, 200	—21, 278	—22, 382	—182, 763
Net windfall profit tax	**22, 907**	**23, 778**	**24, 588**	**25, 771**	**27, 017**	**227, 723**

[1] The Act would raise a small amount of income tax revenue in 1979 because the estimates assume that the tax on newly discovered oil reduces intangible drilling deductions in that year.

Note: Details may not add to totals because of rounding.

Table 4.—Estimated Revenue Effect of the Crude Oil Windfall Profit Tax, Fiscal Years 1980–90

[In millions of dollars]

Item	Fiscal year receipts					
	1980	1981	1982	1983	1984	1985
Gross windfall profit tax	5, 159	20, 955	32, 293	35, 124	37, 429	39, 535
Change in income taxes	−1, 987	−7, 518	−12, 749	−15, 166	−16, 285	−17, 309
Net windfall profit tax	**3, 172**	**13, 436**	**19, 543**	**19, 958**	**21, 144**	**22, 227**

Item	Fiscal year receipts					
	1986	1987	1988	1989	1990	Total 1980–90
Gross windfall profit tax	40, 923	42, 524	44, 181	46, 270	48, 538	392, 931
Change in income taxes	−18, 147	−18, 923	−19, 758	−20, 677	−21, 766	−170, 285
Net windfall profit tax	**22, 776**	**23, 601**	**24, 423**	**25, 593**	**26, 772**	**222, 646**

Note: Details may not add to totals because of rounding.

Table 5.—Estimated Budget Effect of Residential Energy Tax Credits, Calendar Years 1980–90

[In millions of dollars]

Provision	1980	1981	1982	1983	1984	1985
Solar, wind and geothermal credit, 40 percent	−40	−50	−65	−82	−119	−177
Business energy tax credit to landlords, 15 percent	−2	−3	−4	−15	−19	−24
Total	**−42**	**−53**	**−69**	**−97**	**−138**	**−201**

Provision	1986	1987	1988	1989	1990	1980–90
Solar, wind and geothermal credit, 40 percent						−533
Business energy tax credit to landlords, 15 percent						−67
Total						**−600**

Table 6.—Estimated Budget Effect of Residential Energy Tax Credits, Fiscal Years 1980–90

[In millions of dollars]

Provision	1980	1981	1982	1983	1984	1985
Solar, wind, and geothermal credit, 40 percent	−6	−42	−52	−67	−88	−128
Business energy tax credit to landlords, 15 percent	−1	−2	−3	−7	−17	−20
Total	**−7**	**−44**	**−55**	**−74**	**−105**	**−148**

Provision	1986	1987	1988	1989	1990	1980–90
Solar, wind, and geothermal credit, 40 percent	−150					−533
Business energy tax credit to landlords, 15 percent	−17					−67
Total	**−167**					**−600**

Table 7.—Estimated Budget Effect of Business Energy Tax Incentives, Calendar Years 1980–90

[In millions of dollars]

Provision	1980	1981	1982	1983	1984	1985
Business energy investment credits:						
Solar and wind property, including solar process heat equipment, 15% energy credit	−10	−19	−34	−108	−282	−497
Geothermal equipment, 15% energy credit	−1	−2	−2	−5	−8	−11
Ocean thermal energy conversion equipment, 15% energy credit	(2)	(2)	(2)	(2)	−2	−2
Small-scale hydroelectric facilities, 11% energy credit	−7	−13	−17	−21	−81	−144
Cogeneration equipment, 10% energy credit	−31	−53	−78	−82	−65	−36
Petroleum coke and pitch, regular investment credit and accelerated depreciation	−25	−30	−34	−38	−43	−47
Certain equipment for producing feedstocks			(1)	−22	−29	−28
Alumina electrolytic cells, 10% energy credit	−1	−1	−1	−1	−1	−1
Coke ovens, 10% energy credit	−37	−46	−56	−59	−45	−23
Biomass equipment, 10% energy credit	(2)	−4	−4	−18	−160	−352
Intercity buses, 10% energy credit	−5	−5	−6	−6	−7	−7
Affirmative commitments, special transition rule			(1)	−448	−358	−202
Total, energy investment credits	**−117**	**−173**	**−232**	**−808**	**−1, 081**	**−1, 350**

Alternative fuel production credit: [4]						
Devonian shale gas, special rule	−9	−26	−45	(4)	(4)	(4)
Qualifying processed wood, phaseout suspension	−2	−13	−25	−21	−8	----
Steam from agricultural byproducts, phase-out suspension	−1	−2	−2	−3	−3	----
Total, production credits	**−12**	**−41**	**−72**	**−24**	**−11**	(4)
Alcohol fuels provisions: [5]	**−3**	**−4**	**−5**	**−7**	**−59**	**−158**
Industrial development bonds:						
Solid waste disposal facilities	(2)	−3	−5	−5	−5	−5
Alcohol from solid waste facilities			(2)	(2)	−1	−1
Small-scale hydroelectric facilities	(2)	(2)	−2	−2	−4	−6
Additions to certain existing hydroelectric facilities			−3	−7	−8	−8
State renewable resource programs	−1	−1	−2	−4	−7	−8
Total, bonds	**−1**	**−4**	**−12**	**−18**	**−25**	**−28**
Tertiary injectants	**−13**	**−10**	**−8**	**−7**	**−6**	**−5**
Total, Business Tax Incentives	**−146**	**−232**	**−329**	**−864**	**−1, 182**	**−1, 541**

Footnotes at end of table.

Table 7.—Estimated Budget Effect of Business Energy Tax Incentives, Calendar Years 1980–90—Continued

[In millions of dollars]

Provision	1986	1987	1988	1989	1990	1980–90
Business energy investment credits:						
Solar and wind property, including solar process heat equipment, 15% energy credit	−78	−30	(1)			−1,058
Geothermal equipment, 15% energy credit	(1)					−29
Ocean thermal energy conversion equipment, 15% energy credit	−1					−5
Small-scale hydroelectric facilities, 11% energy credit	−284	−427	−582	−137	−84	−1,797
Cogeneration equipment, 10% energy credit	−11	(1)				−356
Petroleum coke and pitch, regular investment credit and accelerated depreciation	−52	−58	−63	−68	−74	−532
Certain equipment for producing feedstocks	−22	−9	(2)			−110
Alumina electrolytic cells, 10% energy credit						−123
Coke ovens, 10% energy credit	−7	−3	−1			−277
Biomass equipment, 10% energy credit	−55	−32	−23	(1)		−648
Intercity buses, 10% energy credit						−36
Affirmative commitments, special transition rule	−90	−42	−12	(1)	(2)	−1,152
Total, energy investment credits	**−600**	**−601**	**−681**	**−205**	**−158**	**−6,012**[3]
Alternative fuel production credit:[4]						
Devonian shale gas, special rule	(4)	(4)	(4)	(4)	(4)	−80
Qualifying processed wood, phaseout suspension						−69

Steam from agricultural byproducts, phase out suspension						—11
Total, production credits	(4)	(4)	(4)	(4)	(4)	—160
Alcohol fuels provision [5]	**—188**	**—228**	**—268**	**—307**	**—347**	**—1,574**
Industrial development bonds:						
Solid waste disposal facilities	—5	—5	—5	—5	—5	—48
Alcohol from solid waste facilities	—1	—1	—1	—1	—1	—7
Small-scale hydroelectric facilities	—8	—29	—66	—85	—81	—283
Additions to certain existing hydroelectric facilities	—8	—8	—8	—8	—8	—66
State renewable resource programs	—9	—9	—9	—9	—9	—68
Total, bonds	—31	—52	—89	—108	—104	—472
Tertiary injectants	**—5**	**—6**	**—6**	**—6**	**—7**	**—79**
Total, Business Tax Incentives	**—824**	**—887**	**—1,044**	**—626**	**—616**	**—8,297** [3]

[1] Less than $5 million.
[2] Less than $1 million.
[3] This total includes $6 million in calendar year liability reductions from 1978 and 1979.
[4] It is assumed that the applicable reference price will be in excess of the credit phase-out range for oil from shale or tar sands, liquid, gaseous or synthetic solid fuel from coal, geopressured brine gas, coal seam gas, tight formation gas, biomass gas, steam from solid agricultural by-products and fuels processed wood qualifying.
[5] The estimates for calendar years 1984–1990 assume that the Federal excise taxes on gasoline, diesel fuel, and other motor fuels will continue at the present rate of 4 cents per gallon. Under present law, these taxes are scheduled to be reduced to 1½ cents per gallon on October 1, 1984, when the Highway Trust Fund is scheduled to expire.

Table 8.—Estimated Budget Effect of Business Energy Tax Incentives, Fiscal Years 1980–90

Provision	1980	1981	1982	1983	1984	1985
Business energy investment credits:						
Solar and wind property, including solar process heat equipment, 15% energy credit	−3	−15	−26	−67	−185	−377
Geothermal equipment, 15% energy credit	(2)	−2	−2	−3	−7	−9
Ocean thermal energy conversion equipment 15% energy credit	(2)	(2)	(2)	(2)	−1	−2
Small-scale hydroelectric facilities, 11% energy credit	−2	−11	−15	−19	−48	−109
Cogeneration equipment, 10% energy credit	−9	−46	−64	−80	−74	−52
Petroleum coke and pitch, regular investment credit and accelerated depreciation	−8	−31	−32	−36	−40	−44
Certain equipment for producing feed stocks			(1)	−7	−28	−29
Alumina electrolytic cells, 10% energy credit	−6	−1	−1	−1	−1	−1
Coke ovens, 10% energy credit	−11	−47	−51	−57	−53	−35
Biomass equipment, 10% energy credit	(2)	−2	−4	−10	−82	−246
Intercity buses, 10% energy credit	−2	−5	−6	−6	−6	−7
Affirmative commitments, special transition rule			(1)	−202	−407	−288
Total, energy investment credits	**−41**	**−160**	**−201**	**−488**	**−932**	**−1, 199**

Alternative fuel production credit: [3]						
Devonian shale gas, special rule	−3	−18	−34	−25	([3])	([3])
Qualifying processed wood, phaseout suspension	−1	−7	−18	−23	−15	−5
Steam from agricultural by-products, phaseout suspension	([2])	−1	−2	−2	−3	−3
Total, production credits	**−4**	**−26**	**−54**	**−50**	**−18**	**−8**
Alcohol fuels provisions	**−1**	**−4**	**−4**	**−6**	**−8**	**−187**
Industrial development bonds:						
Solid waste disposal facilities	([2])	−1	−4	−5	−5	−5
Alcohol from solid waste facilities			([2])	([2])	([2])	−1
Small-scale hydroelectric facilities	([2])	([2])	([2])	−2	−3	−5
Additions to certain existing hydroelectric facilities			−1	−5	−7	−8
State renewable resource programs	([2])	−1	−1	−3	−5	−7
Total, bonds	([2])	**−2**	**−6**	**−15**	**−20**	**−26**
Tertiary injectants	**−4**	**−14**	**−9**	**−8**	**−7**	**−6**
Total, Business Tax Incentives	**−50**	**−206**	**−274**	**−567**	**−985**	**−1,426**

Footnotes at end of table.

Table 8.—Estimated Budget Effect of Business Energy Tax Incentives, Fiscal Years 1980–90—Continued

Provision	1986	1987	1988	1989	1990	1980–90
Business energy investment credits:						
Solar and wind property, including solar process heat equipment, 15% energy credit	−311	−57	−17	(1)		−1,058
Geothermal equipment 15% energy credit	−6	(2)				−29
Ocean thermal energy conversion equipment, 15% energy credit	−2	(2)	(2)			−5
Small-scale hydroelectric facilities, 11% energy credit	−207	−348	−497	−382	−113	−1,751
Cogeneration equipment, 10% credit	−25	−6	(2)			−356
Petroleum coke and pitch, regular investment credit and accelerated depreciation	−49	−55	−60	−65	−71	−491
Certain equipment for producing feed stocks	−25	−16	−5	(2)		−110
Alumina electrolytic cells, 10% energy credit	−1					−12
Coke ovens, 10% energy credit	−16	−5	−2	(2)	(1)	−277
Biomass equipment, 10% energy credit	−218	−45	−28	−13	(1)	−648
Intercity buses, 10% energy credit	−4					−36
Affirmative commitments, special transition rule	−152	−68	−28	−7	(1)	−1,152
Total, energy investment credits	**−1,016**	**−600**	**−637**	**−467**	**−184**	**−5,592**
Alternative fuel production credit: [3]						
Devonian sha e gas, special rule	(3)	(3)			(3)	−80
Qualifying processed wood, phase-out suspension						−69

Steam from agricultural by-products, phase-out suspension						−11
Total, production credits	(3)	(3)	(3)	(3)	(3)	**−160**
Alcohol fuels provisions [4]	**−183**	**−221**	**−261**	**−300**	**−340**	**−1,515**
Industrial development bonds:						
Solid waste disposal facilities	−5	−5	−5	−5	−5	−45
Alcohol from solid waste facilities	−1	−1	−1	−1	−1	−6
Small-scale hydroelectric facilities	−7	−17	−45	−74	−84	−237
Additions to certain existing hydroelectric facilities	−8	−8	−8	−8	−8	−61
State renewable resource programs	−8	−9	−9	−9	−9	−61
Total, bonds	**−29**	**−40**	**−68**	**−97**	**−107**	**−410**
Tertiary injectants	**−5**	**−5**	**−6**	**−6**	**−6**	**−76**
Total Business Tax Incentives	**−1,233**	**−866**	**−972**	**−870**	**−637**	**−8,086**

[1] Less than $5,000,000.
[2] Less than $1,000,000.
[3] It is assumed that the applicable reference price will be in excess of the credit phase-out range for oil from shale or tar sands, liquid, gaseous or synthetic solid fuel from coal, geopressured brine gas, coal seam gas, tight formation gas, biomass gas, steam from solid agricultural by-products and qualifying processed wood fuels.

[4] The estimates for calendar years 1984–90 assume that the Federal excise taxes on gasoline, diesel fuel, and other motor fuels will continue at the present rate of 4 cents per gallon. Under present law, these taxes are scheduled to be reduced to 1½ cents per gallon on Oct. 1, 1984, when the Highway Trust Fund is scheduled to expire.

V. GENERAL EXPLANATION OF THE ACT

A. WINDFALL PROFIT TAX

(Secs. 101–103 of the Act and new secs. 4986–4998, 6050C, 6076, and 7241 of the Code)

Prior Law

Under prior law, there was no Federal excise tax on domestically produced crude oil.

Reasons for Change

The windfall profit tax was necessary because the Administration's decision to phase out price controls on domestically produced crude oil is resulting in large increases in the price of crude oil, especially when considered in conjunction with the recent increases in the world price of oil. Higher crude oil prices are increasing the revenues of oil producers and royalty owners dramatically. Conversely, other segments of the domestic economy are bearing those additional price increases.

The windfall profit tax will achieve an equitable distribution of the gains from decontrol and from extraordinary increases in world oil prices. The tax will allow oil producers and royalty owners to retain an adequate share of the gains from higher oil prices, while generating substantial federal revenues to be used for the overall public welfare. Without such a tax, decontrol probably could not go forward. The tax was structured to minimize adverse effects on domestic oil production. Features of the tax designed to achieve this goal include the special tax rates for independent producers and the special tax rate for new, heavy and tertiary oil.

Congress believed that the proceeds from the tax should finance energy spending programs and relief for consumers, who must pay higher energy prices. The Act includes guidelines on the use of the funds raised by the tax which are intended to further these goals.

Explanation of Provisions

Overview

The windfall profit tax is a temporary excise, or severance, tax on domestically produced crude oil. All taxable crude oil is classified in one of three tax tiers. The structure of the tax is essentially the same for all tiers: the tax is equal to the taxable windfall profit multiplied by the applicable tax rate. The taxable windfall profit is generally equal to the selling price of the oil minus an adjusted base price and an adjustment for State severance taxes. The three tiers differ in the tax rate which is applied and the adjusted base price which is used. Cer-

tain kinds of producers either are exempt entirely from the tax, or are eligible for reduced tax rates, on part or all of their production.

Tier one of the tax consists of oil which would have been lower or upper tier oil had previous price controls been continued. Tier two consists of oil which is stripper oil or production from a National Petroleum Reserve. Tier three oil consists of newly discovered oil, certain heavy oil, and incremental tertiary oil.

The base price for tier one oil is the May 1979 upper tier ceiling price for that oil, less $0.21. The base price for tier one oil should average about $12.81 a barrel; i.e., the $13.02 actual May 1979 average for upper tier oil minus $0.21. The base prices for tier two and tier three oil are such that, for oil of national average grade, quality and location, the tier two base price is $15.20 a barrel and the tier three base price is $16.55 a barrel. All base prices are adjusted for inflation. In addition, the tier two and tier three base prices are adjusted for quality and location differentials. A "kicker" of 2 percent a year applies to the inflation adjustment to the tier three base price.

The tax rate applied to the windfall profit is 70 percent for tier one, 60 percent for tier two, and 30 percent for tier three. Independent producers are allowed reduced rates on up to 1,000 barrels a day of their combined production of tier one and tier two oil. For tier one oil the reduced rate is 50 percent, and for tier two oil the reduced rate is 30 percent.

State and local governments, certain qualifying charitable medical facilities and educational institutions, and Indian tribes and Indians over whom the United States exercises trust responsibilities are exempt from the tax. There also are exemptions for new oil produced in most of Alaska and for front-end tertiary oil.

The entire windfall profit tax phases out over a 33-month period beginning after December 31, 1987, or when cumulative revenues raised by the tax reach $227.3 billion, whichever is later. However, the phase-out will begin no later than January 1991.

1. Tier One Oil

Treatment under price controls

Old pricing regulations.—Under Department of Energy (DOE) price control regulations as they stood prior to the President's decontrol program, lower tier oil was most oil produced on a property which first began production prior to 1973. Lower tier oil was subject to a ceiling price equal to the sum of (1) the highest posted field price for that oil on May 15, 1973, (2) $1.35 per barrel, and (3) certain post-1975 increases intended to provide adjustments for inflation and production incentives. The May 1979 lower tier ceiling price averaged $5.91 per barrel.

The volume of lower tier oil on a property was determined by computing a property's "base production control level" (BPCL). Oil production at or below this level was classified as lower tier oil.[1] Prior to

[1] Once a property had produced an amount of oil above its adjusted BPCL, if it subsequently produced an amount of oil below the level of its adjusted BPCL, the difference between the actual production and the adjusted BPCL resulted in a "cumulative deficiency." Before a property's production in excess of its adjusted BPCL could be classified as upper tier oil, any amount of oil by which the property fell below its BPCL for all prior months, i.e., its cumulative deficiency, had to be eliminated or "paid back."

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the decontrol program, a property's BPCL was the lesser of (1) the average daily amount of all oil produced from the property in 1972, or (2) the average daily amount of lower tier oil produced from the property in 1975. In the case of certain properties, the BPCL could be adjusted downward to project the 1972–1975 rate of production decline on the property.

Under DOE regulations, upper tier oil is the amount of oil produced from a property in excess of its adjusted BPCL, less the amount of any cumulative deficiency. This includes all production from properties which first began production after 1972, including production from the Sadlerochit reservoir on Alaska's North Slope. However, it does not include oil produced from a stripper well property, oil classified as newly discovered, or incremental production from a qualified tertiary enhanced recovery project.

Generally, the ceiling price for upper tier oil from a property was the highest posted field price for uncontrolled oil on September 30, 1975, less $1.32 per barrel, plus certain post-1975 increases intended to offset inflation. The average May 1979 ceiling price per barrel of upper tier crude oil was $13.02.

Decontrol regulations.—Pursuant to a rule published by the Economic Regulatory Administration of the DOE on April 12, 1979, a producer may elect to have the BPCL for any property be the average daily production of lower tier oil from the property for the six-month period ending March 31, 1979. For properties for which the producer elects to use this BPCL, the BPCL is reduced by 1.5 percent per month for 1979. The first such adjustment was effective as of June 1, 1979, and was calculated as if the adjustment had become effective January 1, 1979. Therefore, if an election was made for a property, its BPCL was reduced by 9 percent, effective June 1, 1979 (six months × 1.5 percent).

Effective June 1, 1979, the rule eliminated all existing cumulative deficiencies. However, cumulative deficiencies may be built up in the future and will reduce the amount of oil eligible for the upper tier price.

On January 1, 1980, the BPCL decline rate was increased from 1.5 percent to 3 percent per month. The 3-percent decline factor applicable to 1980 and 1981 is available to all properties, including those electing not to use the updated BPCL in 1979.

The effect of the DOE pricing decline curve is to phase down the lower tier of price controls so that relatively little lower tier oil (19 percent of the original updated BPCL) will remain just before price control authority expires after September 30, 1981.

Under the DOE rule published on April 12, 1979, oil produced from "marginal properties" was established as a new classification of oil generally eligible to receive upper tier prices. Pursuant to this rule, specific properties qualify as "marginal" depending upon the average production level at different average well depths. On June 1, 1979, the BPCL for a marginal property was reduced to 20 percent of the average daily production of lower tier oil from that property for the last six months of 1978, and the BPCL for marginal properties was reduced to zero on April 1, 1980.

The Administration is eliminating upper tier oil between January 1980 and October 1981 by gradually increasing the amount of oil whose price is deregulated. For each month beginning January 1980, the price of 4.6 percent of upper tier oil is deregulated (i.e., 9.2 percent in February 1980, etc.).

The Act

Tier one oil.—Under the Act, tier one includes all domestically produced crude oil other than any oil specifically put in tiers two or three of the tax or explicitly exempted from the tax by the Act.

Tax computation.—The Act provides that each barrel of tier one oil is subject to a tax equal to 70 percent of the windfall profit. The windfall profit is the difference between the oil's actual selling price and the sum of the adjusted base price for the oil and the State severance tax adjustment, described below. (However, independent producers are allowed a special 50-percent rate, described in section 4 below, on up to 1,000 barrels a day of qualified production.)

The base price for tier one oil is the May 1979 upper tier ceiling price for production from the property, reduced by 21 cents. The base price, which is determined on a property-by-property basis, is adjusted quarterly for post-June 1979 increases in the GNP implicit price deflator. This adjustment, however, is lagged by two quarters. (For more detail on the inflation adjustment, see section 9 below.) The windfall profit subject to the tier one tax then is reduced by so much of the applicable State severance tax as results from the increase in the price of the oil over its adjusted base price. (For more detail on the severance tax adjustment, see section 9 below.)

In the case of production from properties which had no upper tier oil in May 1979, the tier one base price is the upper tier ceiling price which would have applied to that production, under the March 1979 energy regulations, if it had been produced and sold in May 1979 as upper tier oil, reduced by 21 cents. The upper tier ceiling price for production from such a property must be computed in accordance with the historic referents applicable for price control purposes under the energy regulations in effect in March 1979.

2. Tier Two Oil

Treatment under price controls

Stripper properties.—The Trans-Alaska Pipeline Authorization Act provided a statutory exemption from price controls for the first sale of crude oil produced from stripper well leases. For this exemption, a stripper well lease was defined as a property whose average daily production during the preceding calendar month did not exceed the qualifying limits set by the statute. This test for stripper well lease qualification was modified by the Emergency Petroleum Allocation Act of 1973 from one based on production levels during the preceding calendar month to one based on production levels during the preceding calendar year. The Energy Policy and Conservation Act of 1975 reimposed controls on stripper oil, but the Energy Conservation and

Production Act once again exempted stripper oil from controls. However, it provided that to qualify for this exemption a property's average daily per well production of crude oil (excluding a condensate recovered in non-associated production) must have been 10 barrels per day or less during any consecutive 12-month period beginning after December 31, 1972. This definition of stripper oil is still in effect.

National petroleum reserves.—There are four major Federal enclaves of oil production, all of which originally were under the Navy's jurisdiction: (1) Elk Hills, California, (2) Buena Vista, California, (3) Teapot Dome, Wyoming, and (4) Point Barrow, Alaska. Prior to 1976, these areas were part of the Naval Petroleum Reserve. The Naval Petroleum Reserves Production Act of 1976, however, transferred the Point Barrow reserve (no. 4) from the Navy to the Department of the Interior, and named it a National Petroleum Reserve. The DOE Reorganization Act of 1977 transferred the other three reserves from the Navy to DOE.

Production from the three Federal reserves subsequently transferred to DOE was authorized by the Naval Petroleum Reserves Production Act of 1976. First sales of this production owned by the United States are not subject to price regulation.

The Act

Tier two oil.—Tier two consists of two categories of oil not subject to price regulation under the June 1979 energy regulations: (1) oil produced from a stripper well property, and (2) oil from an economic interest in a National Petroleum Reserve held by the United States.

Generally, a stripper well property is defined in accordance with the Energy Conservation and Production Act, as interpreted by the June 1979 energy regulations, i.e., any property from which the average daily per well production has been 10 barrels or less for any consecutive 12-month period after 1972. However, tier two oil from stripper well properties does not include any production which is in tier three of the tax. Therefore, tier two does not include production from a stripper well property which is newly discovered oil, heavy oil, or incremental tertiary oil. In addition, the Act provides that oil may not constitute production from a stripper well property if any portion of the property has been transferred after 1978 and if the production would not have been so classified if the transfer had not taken place. This rule applies equally to production from the transferred and retained portions of the property. A similar rule applies to heavy and newly discovered oil properties.[2]

Tier two also includes oil attributable to an economic interest in a National Petroleum Reserve held by the United States. These reserves are located at Elk Hills and Buena Vista, California, and Teapot Dome, Wyoming.[3] (Oil from the National Petroleum Reserve at Point

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[2] Thus, for example, production from a farmout lease of a property which was in production during 1978, or from an outer continental shelf lease executed prior to January 1, 1979, does not qualify as newly discovered oil under the Act.

[3] Even though the jurisdiction over these reserves was transferred from the Navy in 1976, they are still technically called Naval Petroleum Reserves. The Act's reference to National Petroleum Reserves is intended to refer to these reserves. A technical correction is necessary to clarify this point.

Barrow, Alaska, is exempt from tax because it would be produced from a well located north of the Arctic Circle.) Other Federally owned production, and any oil attributable to an economic interest in a National Petroleum Reserve not held by the United States, is classified in accordance with the tax's other rules.

Tax computation.—The Act provides that each barrel of tier two oil is subject to a tax equal to 60 percent of the windfall profit. The windfall profit is the difference between the actual selling price and the sum of the oil's adjusted base price and the State severance tax adjustment. (However, independent producers are allowed a special 30-percent tax rate, described in section 4 below, on up to 1,000 barrels a day of qualified production.)

The base price for tier two oil essentially is $15.20 a barrel, adjusted upward or downward for the grade, quality and location of the oil. The base price, which is determined on a property-by-property basis, is adjusted quarterly for post-June 1979 increases in the GNP implicit price deflator. The inflation adjustment, however, is lagged by two quarters. (For more detail on the inflation adjustment and the severance tax adjustment, see section 9 below.)

The exact base price for tier two oil from any particular property is established by an interim rule for months prior to the earlier of October 1980 or the effective date of Treasury regulations which prescribe a permanent rule for setting tier two base prices. Under the interim rule, the tier two base price for oil from any property is the product of the highest posted price [4] for December 31, 1979, for uncontrolled crude oil of the same grade, quality, and field as the oil for which a base price is being set, multiplied by the fraction 15.20/35. Postings made after January 14, 1980, however, may not be taken into account. In the absence of a December posting for oil of the same grade, quality, and field, the December 1979 posting in the nearest domestic oil field for which prices were posted for oil of that grade and quality must be used.

The interim base price formula is intended to result in an array of base prices such that uncontrolled oil whose grade, quality, and location equals the average for all domestic oil (excluding North Slope Alaskan oil) will have a base price of approximately $15.20; oil above or below that average will have a base price proportionately higher or lower than $15.20. The interim base price formula should yield, as to oil of any grade, quality, and field, a tier two base price which approximates the price at which that oil would have sold in December 1979 if all domestic oil were uncontrolled and if the average price for all domestic oil (other than North Slope Alaskan oil) were $15.20 a barrel. (This formula, of course, assumes

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[4] A posted price is a bona fide, written, public offer of general applicability to purchase crude oil from all producers in that field or area. See, e.g., FEA Rul. 1977–1, pt. III., 42 Fed. Reg. 3628 (Jan. 19, 1977).

For a posted price to qualify for use in determining a producer's base price, the price has to be published in writing by a purchaser of a substantial volume of crude oil in the field. A posted price does not, for example, include a price offered by a purchaser who simply offers to buy oil at a figure (say) $1 higher than whatever prices are posted by the purchasers who are purchasing most of the oil in a particular oil field.

that the price for any particular type of oil was not abnormal in December 1979.) The data available during the consideration of the Act on December 1979 prices, posted as of January 14, 1980, for uncontrolled oil suggested that $35 was the appropriate amount to use in the formula's denominator to achieve this result.

To ensure that this formula does not unduly penalize producers in fields where December 1979 posted prices were unusually low, the Act provides a minimum tier two base price equal to the property's May 1979 upper tier ceiling price plus $1.00. For properties from which no oil was produced and sold in May 1979 as upper tier oil, the minimum base price is the upper tier ceiling price which would have applied to the oil, under the March 1979 energy regulations, had it been produced and sold in May 1979 as upper tier oil, plus $1.00.

For months after the earlier of September 1980 or the effective date of Treasury regulations which prescribe a permanent rule for setting base prices, the tier two base price for oil from any property must be determined in accordance with the method prescribed in those regulations. The Treasury regulations prescribing the permanent method of determining tier two base prices must estimate the price at which oil from a particular property would have sold in December 1979 if all domestic oil had been uncontrolled and the average price for domestic crude oil, other than North Slope Alaskan oil, had been $15.20. Thus, if oil from a particular property typically sells for 80 percent of the price of oil of national average grade, quality and location, based on market price differentials prevailing in December 1979, its tier two base price should generally be 80 percent of $15.20, or $12.16.

The interim rule was not adopted as the permanent method of setting tier two base prices simply because Congress was not certain that it would lead to an array of base prices such that uncontrolled oil of national average grade, quality, and field would have a base price of $15.20. The $35 price used in the denominator of the interim rule is based on preliminary data for December 1979 prices posted as of January 14, 1980, and more complete data will be available to the Secretary later in 1980. In view of the more complete data, the Secretary may want to take into account the increase in December postings which occurred in late January and February, although this may require raising the denominator above $35. Also, the Secretary may determine, after analyzing the data, that a formula based on actual selling prices, not posted prices, would approximate more closely the desired result.

Congress was aware that the interim rule might lead to inequities in the case of oil produced in California and certain other areas because its December 1979 price was much lower, relative to the national average, than it had been in prior years and is likely to be in the future. That is why Congress included the minimum interim base price in the Act. The Act's guidelines for prescribing regulations for determining base prices gives the Secretary enough flexibility to devise a permanent solution to this problem.

3. Tier Three Oil

a. Tier three oil generally

Tier three consists of newly discovered oil, heavy oil, and incremental tertiary oil.

Tax computation.—The Act provides that each barrel of tier three oil is subject to a tax equal to 30 percent of the windfall profit. The windfall profit is the difference between the oil's actual selling price and the sum of its adjusted base price and the State severance tax adjustment. The base price for tier three oil essentially is $16.55 a barrel, adjusted upward or downward for grade, quality, and location. The base price, which is determined on a property-by-property basis, is adjusted quarterly for post-June 1979 increases in the GNP implicit price deflator plus 2-percent. The inflation adjustment, however, is lagged by two quarters. (For more detail on the inflation adjustment and the severance tax adjustment, see section 9 below.)

The exact base price for tier three oil is established by an interim rule for months prior to the earlier of October 1980 or the effective date of Treasury regulations which prescribe a permanent rule for setting tier three base prices.

More specifically, the tier three base price for oil from a particular property must be determined in exactly the same manner as that applicable to tier two, as described in section 2 above, except that "$16.55" must be substituted for "$15.20" in the formulas. In addition, the minimum interim base price for tier three oil is the May 1979 upper tier ceiling price for oil from the property plus $2.

b. Newly discovered oil

Treatment under price controls

Under DOE regulations published on May 2, 1979, "newly discovered oil" is defined as crude oil which is sold after May 31, 1979, and which is produced from (1) an outer continental shelf area for which the lease was entered into on or after January 1, 1979, and from which there was no production in calendar year 1978, or (2) an onshore property from which no crude oil was produced in calendar year 1978. Oil produced from a property, as defined by DOE regulations, which previously had been developed but from which there was no production in calendar year 1978 is treated as newly discovered oil under this definition. The determination of whether crude oil production from a particular property may be sold as newly discovered crude oil on or after June 1, 1979, is made by the producer, subject to DOE's possible review.

The price of newly discovered oil sold after June 1, 1979 is not controlled.

Definition of newly discovered oil

For windfall profit tax purposes, the term "newly discovered oil" generally has the same meaning as is given to that term by the June

1979 energy regulations. However, for tax purposes, Congress clarified that newly discovered oil includes production from a property which did not produce oil in commercial quantities during calendar year 1978. Thus, it includes production from a property on which oil was produced in 1978 if that production was incident to the drilling of exploratory or test wells and was not part of continuous or commercial production from the property during 1978.

c. Heavy oil

Treatment under price controls

Effective for sales on or after August 17, 1979, Executive Order No. 12153 exempted certain heavy crude oil [5] from price controls. For purposes of this order, the term 'heavy crude oil" means all crude oil produced from a property if, during the last month prior to July 1979 in which crude oil was produced and sold from the property, such crude oil has a weighted average of 16.0 degrees API or less, corrected to 60 degrees Fahrenheit.

Under Executive Order No. 12186, the exemption from price controls for heavy oil was extended to production from properties which had a weighted average gravity of 20.0 degrees API or less, corrected to 60.0 degrees Fahrenheit, for the last month prior to July 1979 in which crude oil was produced and sold from the property. This extension of the exemption from price controls applied to first sales of crude oil on or after December 21, 1979. The Administration did not propose that this expanded definition of heavy oil be used for the windfall profit tax.

Production from a single well with multiple completions into separate properties also may be exempted from price controls if it meets the applicable gravity requirements and the DOE rules pertaining to production from such wells.

DOE regulations provide that crude oil injected as a diluent into a well bore on a heavy oil property and subsequently recovered retains the character it had prior to its injection. Therefore since a diluent typically has a higher gravity than heavy oil, oil used as a diluent and recovered from the property generally does not qualify as heavy oil. The DOE regulations require an identification of heavy oil produced in conjunction with a diluent.

Definition of heavy oil

For windfall profit tax purposes, heavy oil is defined as (1) oil from a property which had a weighted average gravity of 16.0 degrees API or less, corrected to 60 degrees Fahrenheit, for the last month of production prior to July 1979, or (2) oil from a property with a weighted average gravity of 16.0 degrees API or less, cor-

[5] The weight of crude oil generally is measured by its gravity. The gravity of crude oil is an indicator of the thickness or viscosity of a particular crude oil. The weight of oil normally is measured in degrees on the American Petroleum Institute (API) scale. On this scale oil with the lowest specific gravity has the highest API gravity. Generally, the higher the API gravity, the greater the value of the oil. The lower the gravity of crude oil, the more tarlike and difficult to produce it becomes. Crude oils vary in gravity up to a high of around 40 degrees API. However, most domestic crude oils range from 27 degrees to 35 degrees API.

rected to 60 degrees Fahrenheit, for the taxable period. In the latter instance the weighted average gravity of the oil is determined separately for each taxable period. Therefore, production from a property may qualify as heavy oil for one taxable period but not for another taxable period. As a result, producers must maintain records adequate to substantiate the weighted average gravity of the oil produced for any taxable period for which classification as heavy oil is claimed based on gravity during the taxable period.

In the case of production from a single well which has multiple completions into more than one producing property, production from one of these properties could qualify as heavy oil if it meets the 16.0 degree requirement and the producer satisfies the rules pertaining to multiple completion wells under the energy regulations. Therefore, such wells generally would have to consist of more than one separate tubing string running inside the casing, each of which carried crude oil from a different property, and have adequate meters and similar equipment. Production from "commingled wells" would not qualify under this standard.

d. Incremental tertiary oil

Treatment under price controls

Under DOE regulations, first sales of incremental crude oil resulting from the implementation or expansion of a "qualified tertiary enhanced recovery project" are exempted from the otherwise applicable ceiling price limitations. A qualified tertiary enhanced recovery project is a project that involves one or more of several specified chemical, fluid, or gaseous recovery techniques and that would be uneconomic at the otherwise applicable ceiling price. The following nine specific techniques qualify as tertiary recovery: (1) miscible fluid displacement, (2) steam drive injection, (3) microemulsion or micellar emulsion flooding, (4) in situ combustion, (5) polymer augmented flooding, (6) cyclic steam injection, (7) alkaline or caustic flooding, (8) carbon dioxide augmented water flooding, and (9) immiscible carbon dioxide displacement.

Producers may self-certify their projects if they employ certain processes; otherwise, the project must be approved in advance by DOE.

In the case of a new tertiary project, incremental tertiary oil is the amount produced in excess of the amount that could have been produced from the property through maximum feasible production from the ordinary recovery method used prior to certification. In the case of an expansion of an existing project, the incremental tertiary oil is the amount produced as a result of the expansion over the amount that could have been produced through maximum feasible production from the use of the pre-expansion recovery methods. In the case of a tertiary project that antedated the DOE regulations, incremental tertiary oil is that amount produced by continuing either the project, or a high-cost phase of the project, in excess of the amount that could have been produced through maximum feasible production from methods other than the tertiary method, or any phase thereof, which would be discontinued in the absence of a price incentive.

Definition of incremental tertiary oil

Overview

For the windfall profit tax, incremental tertiary oil is production in excess of a base level on a property on which a qualified tertiary recovery project has been undertaken. The nonincremental oil (i.e., the amount of production up to the base level) remains in the otherwise applicable tier.

Generally, only production from projects started after May 31, 1979, may be classified as incremental tertiary oil. (However, special rules allow incremental tertiary treatment to expansions of projects implemented before, but expanded after, May 1979, and to projects certified by DOE under the June 1979 energy regulations and begun before June 1979.)

For windfall profit tax purposes, a tertiary recovery method is generally one of the nine specified in the June 1979 energy regulations as being eligible for use in a tertiary project for price decontrol purposes. (There are differences, however, between these methods and those specified in the final DOE regulations on tertiary projects issued on August 29, 1979, and made effective on October 1, 1979.) The term "tertiary recovery method" also includes other tertiary methods, not listed above, which are approved by the Secretary of the Treasury, but it excludes immiscible natural gas injections and water flooding.

Incremental tertiary oil on a property is that amount of production which exceeds a base level. The base level for a property is the average monthly amount of crude oil removed from the property during the six-month period ending March 31, 1979, reduced by a decline factor. The base level must be computed under rules similar to those applicable in determining the base production control level under the June 1979 energy regulations.

The decline factor by which the base level is reduced equals the sum of (1) 1 percent of the initial base level for each month beginning after 1978 and before the first month beginning after the project's beginning date, and (2) 2½ percent of the initial base level for each month which begins thereafter, but before the month for which the base level is being determined.[6] This statutory decline rate applies to all qualified tertiary recovery projects. However, projects certified by DOE under the June 1979 energy regulations are deemed to have an amount of incremental tertiary oil which is not less than the incremental production determined for those projects under the June 1979 regulations.

If a tertiary project is expected to affect production from less than an entire property, the part expected to be affected by the project is treated as a separate property from the part not expected to be affected by the project. The incremental tertiary oil on a property comes from tier one and tier two in proportion to the amount of oil which would otherwise have been in those tiers. To determine exactly which barrels from each tier are eligible for classification as incremental tertiary oil, the producer first releases oil from each tier in order of its removal price, starting with the barrel with the highest selling price.

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[6] For those few qualified projects which began before 1979, the 2½-percent decline rate starts in January 1979.

Qualified projects

Overview.—For tax purposes, a qualified tertiary recovery project is either (1) a qualified tertiary enhanced recovery project with respect to which a pricing certification has been approved and is in effect under the June 1979 energy regulations, or (2) any project for enhancing recovery of crude oil which meets three specific requirements set out in the tax.

With regard to each project to which the three requirements of the tax apply (as discussed below), a certification must have been made that these three requirements had been met. Such a certification must be made either by a petroleum engineer ("self-certification") or by the appropriate jurisdictional agency ("regulatory certification").

Use of tertiary method and increase in amount of crude oil.—The first requirement for qualification as a tertiary recovery project is that the project involves the application of a tertiary recovery method according to sound engineering principles and that the method can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which ultimately will be recovered from the project area. The determination of whether an expected increase in production is more than insignificant depends upon the facts and circumstances of each case. When a tertiary project is expected to affect a portion of a property, that portion is treated as a separate property; therefore, significance is measured in relation to total production reasonably expected from the portion of the property treated as a separate property.

Production from a tertiary recovery project will not be treated as incremental tertiary oil for tax purposes if the producer uses the project merely as a method of accelerating (as opposed to increasing) the total amount of oil expected to be recovered from the property or project area. The requirement that the tertiary project be expected to increase production from the property by more than an insignificant amount could be satisfied by showing that the project would reduce the expected decline in production significantly below what it otherwise would be; that is, an actual increase in production over earlier levels is not necessary.

Project beginning date.—The second requirement is that the project begin after May 1979.

The project's beginning date, i.e., the time after which production may qualify, must be established by the producer's records. Generally, the beginning date is the later of (1) the date of submission to the Secretary of the certification for the project, or (2) the date on which the tertiary injection initially is made.[7] Thus, some production may be

[7] The general requirement that the project's beginning date must be after May 1979 necessitates that the project actually have begun after that date. This requirement is not satisfied merely because the Secretary is furnished the project's certification after May 1979. Thus, for purposes of determining whether the project started after May 1979, the phrase "project beginning date" (as used in section 4993(c)(2)(B)) is intended to refer to the date on which the project first was implemented. On the other hand, the term "project beginning date," as used in section 4993(d)(2) for purposes of computing the base level under section 4993(b), means the later of the date on which (1) the tertiary injections begin, or (2) the Secretary is furnished the project's certification. A technical correction may be necessary to clarify this point.

eligible for classification as incremental tertiary oil prior to the time at which the producer could establish that the tertiary method has affected the reservoir. Nevertheless, a larger project will not be considered to have commenced if the tertiary injectant is utilized merely on a pilot or experimental basis in a smaller area. Therefore, in the case of a pilot project, tertiary injections in the area of the pilot project would determine the beginning date of the pilot project but not the beginning date of any subsequent full scale project affecting a larger area. Similarly, mere preparation or planning for the tertiary process, such as drilling an injection well, would not be sufficient to establish any project's beginning date.

For windfall profit tax purposes, a significant expansion of a project is a separate project. As such, an expansion must satisfy the tax's requirements independently from the application of those rules to the project which is being expanded. As a result, an expansion might qualify under the tax even though the project which is being expanded does not, e.g., where the first project's beginning date was prior to June 1, 1979, or qualifies in a different manner, such as pursuant to a DOE certification.

A tertiary project may be expanded in several ways. For example, a project may be expanded geographically by increasing the area from which production can reasonably be expected to be affected by the use of the tertiary recovery method. An expansion also could occur through a significantly more intensive use of a tertiary recovery method, or a significant expansion of tertiary activities, within a pre-existing project area. In addition, a pre-June 1979 project which was curtailed significantly before 1980, and which was expanded to its pre-curtailment level after that date, would be treated as a new project due to a significant expansion. A project would be considered to have been curtailed significantly, for example, if the average post-curtailment concentration of injected gases was reduced by 35 percent or more from the average pre-curtailment concentration of injected gases. For purposes of making this determination, the entire pre-curtailment project area would be compared with the same area after the curtailment.

Delineation of project area.—The third requirement is that the portion of the project to be affected by the project be adequately delineated. If a tertiary project is expected to affect production from less than an entire property, the part expected to be affected by the project is treated as a separate property from the part not expected to be affected by the project.

Self-certification.—A project may qualify if it meets the three requirements listed above if the operator submits to the Secretary such information and forms as may be required by regulations, including certification from a petroleum engineer that the project meets the tax's three requirements.

Regulatory certification.—As an alternative to self-certification, tertiary projects may be certified by a competent governmental regulatory body as meeting the three requirements. In the case of projects located on lands managed by the Federal government, including the Outer Continental Shelf, projects may be certified by the U.S. Geological Survey. Other projects may be certified by the appropriate State agency designated by the governor of the State in which the project is

located. If a State agency is to certify projects, the Secretary must be notified by the governor. If no State regulatory body is designated by the governor to certify projects within 180 days of the effective date of the tax, projects located in such jurisdictions may be certified by the U.S. Geological Survey until such time as a State agency is designated. The "appropriate State agency" is one that is authorized by State or local law to administer generally applicable regulatory or tax provisions pertaining to mineral or oil production, if the State has such an agency.

Generally, a regulatory certified project must satisfy the same three requirements as those applicable to self-certified projects. In addition, the operator must submit a certification that a jurisdictional agency has approved the project as meeting those requirements and any periodic certifications required by the Secretary that such approval still is in effect.

If a regulatory body revokes its certification of a project, upon examination by the IRS the project is treated as having been self-certified. (For more detail on review standards see "IRS examination" below.) Therefore, to qualify for preferential windfall profit tax treatment as a qualified tertiary recovery project, such a project would have to meet the tax requirements pertaining to self-certified projects.

Continuing tertiary qualification.—A project generally is qualified only so long as the tertiary method continues to affect the reservoir. Thus, oil produced after the discontinuation of a tertiary project no longer is considered to be eligible for classification as incremental tertiary oil if the process' effect on the reservoir has terminated. Generally, qualification would be retained for the period which is specified, in accordance with sound engineering principles, in the project's certified plan. This period normally would be determined on a case-by-case basis, depending upon such factors as the size of the project, the characteristics of the reservoir, and the particular process involved. For instance, some steam injection processes, *e.g.*, cyclic steam injection, are interrupted periodically to produce oil (together with condensed steam) from the same well or wells which are used for the steam injections. Under the Act, each oil producing interval of such a process would have to be scheduled in light of sound engineering principles and of the transitory effect of the injections. Therefore, if the injections were terminated, production no longer would qualify as incremental tertiary oil after the last injection could no longer reasonably be expected to affect the reservoir. Similarly, some recovery processes, *e.g.*, miscible (carbon dioxide) fluid-displacement, microemulsion flooding, or polymer augmented flooding, may not require continuous or sustained injections of tertiary gases or liquids to have the process affect production from the reservoir. For example, some carbon dioxide injection processes may result in the creation of artificial pressure in a reservoir. Such artificial pressure may allow oil displacement for a period beyond the time during which there are injections. Assuming that an adequate amount of carbon dioxide, as determined in accordance with the plan and sound engineering principles, was pumped into the reservoir, the production could qualify as incremental tertiary oil in the absence of contemporaneous injections.

IRS examination.—All self-certified projects are subject to the generally applicable rules pertaining to reviews by the IRS upon examination. In other words, the producer has to establish that the facts underlying the claimed treatment as incremental tertiary production, in fact, had satisfied the requirements for that classification.

A special examination rule applies, however, to projects certified by a regulatory body prior to the time that tax treatment as incremental tertiary oil was claimed. (Prior to a regulatory certification, these projects could be self-certified and, thus, be subject to the rules pertaining to self-certifications for that period.) Project certifications issued by a regulatory body are subject to a "substantial evidence" rule.[8] Under this rule, the tax qualification of a project certified by a regulatory body would be sustained unless the Internal Revenue Service established that the certification was not supported by substantial evidence or presented substantial evidence that the project did not qualify for certification. In making such a review, the IRS could "go behind" the certification issued by the regulatory body. If the IRS established that the certification was not supported by substantial evidence, or presented substantial evidence that the project did not qualify for certification, the producer then could introduce additional evidence to sustain the classification. At that point, the generally applicable rules pertaining to reviews would apply, just as if the project were self-certified.

The application of the substantial evidence rule to certifications issued by a regulatory body applies to issues concerning both the project's initial qualification and its continuing qualification.

This substantial evidence rule was adopted, in part, because a regulatory certification should aid the Internal Revenue Service in enforcing the tax by having producers generate documentary evidence in support of the tertiary project prior to any examination and by having that evidence reviewed independently, in advance of being treated as incremental tertiary oil for windfall profit tax purposes, by an expert regulatory authority. Furthermore, since the administrative record upon which a regulatory certification was based would be included in the category of material facts necessary for appropriate tax classification, it would be available, with the producer's records, for review and examination by the Service.

If a certification application is denied by a regulatory body, the Service would be free to use that information in a later review of a self-certified project, or upon an examination of a regulatory certification subsequently issued for such a project. This is consistent with the standard of review applicable to natural gas.[9]

The substantial evidence rule allows the Service to disregard a regulatory certification that was issued prefunctorily or was largely unsupported by the documents presented to the regulatory body.

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[8] This standard of review is similar to that contained in the Administrative Procedure Act (5 U.S.C. sec. 705(2)(E)), and found in section 503(b) of the Natural Gas Policy Act of 1978 (Pub. L. 95–621). It also is similar to the standard used by the Tax Court in *Ditter Bros., Inc.* v. *Comm'r*, 72 T.C. 896 (1979) (declaratory judgment as to certain transfers from the U.S.).

[9] The Natural Gas Policy Act of 1978 treats the absence of substantial evidence in an administrative record as substantial evidence against qualification for inclusion in a particular category. *See e.g.*, H. Rept. No. 95–1752, 95th Cong., 2d Sess. 117 (1978) (Conference agreement on section 503 of Pub. L. 95–621).

Advance determination.—In the case of tertiary projects certified by a regulatory body, producers could apply for an advance IRS determination, to be issued within 180 days of the time that the request, together with the information necessary to make a determination, is submitted to the Secretary. Whether information adequate to make such a ruling has been submitted to the Secretary is to be determined on an objective basis.

4. Independent Producers

Overview

The Act allows independent producers to pay reduced tax rates on so much of their combined production of qualifying tier one and tier two oil as does not exceed 1,000 barrels a day, computed on a quarterly basis. For tier one oil the special rate is 50 (rather than 70) percent; for tier two oil the rate is 30 (rather than 60) percent. If an independent producer's qualified production of tier one and tier two oil for any quarter exceeds the amount eligible for reduced rates, the oil eligible for the reduced rates comes from tiers one and two in proportion to the independent producer's production of domestic oil in those tiers for the quarter. In such a case, the particular barrels of oil within each tier which are eligible for reduced rates are determined by beginning with those barrels with the highest removal prices.

For windfall profit tax purposes, the term "independent producer" generally means any person who is defined as being eligible for percentage depletion under section 613A. The term, therefore, generally excludes crude oil refiners and retailers of crude oil and natural gas under the same circumstances in which they are denied the deduction for percentage depletion of oil and gas income. However, the applicability of this exclusion is determined on a quarterly basis, not annually, with retail sales being limited to $1,250,000 for a taxable quarter (instead of $5,000,000 per year).

For an independent producer's production to qualify for the reduced rates, certain conditions must be met. The oil must be attributable to a working interest, not a royalty or other nonoperating interest, and it must satisfy the transfer rules described below. Also, the 1,000-barrel amount must be allocated between related parties.

Working interest

For purposes of determining eligibility for reduced windfall profit tax rates, a "working interest" is an operating mineral interest within the meaning of section 614(d) of the Code. Generally, such an interest must have been in existence as an operating mineral interest on January 1, 1980.

Under the applicable income tax regulations, an "operating mineral interest" includes only an interest in respect of which the costs of producing the oil are required to be taken into account by the taxpayer for purposes of computing the 50-percent limitation of the taxable income from the property in determining the deduction for percentage depletion, or an interest in respect of which such production costs would be so required to be taken into account if the property were in the producing stage. For purposes of determining whether an interest is an operating mineral interest, costs of production do not include intangible drilling and development costs (IDCs),

or expenditures for such items as production taxes payable by owners of non-operating interests. Thus, an interest subject to intangible drilling and development costs would not constitute an "operating mineral interest" except to the extent that it also was subject to the costs of production.

The term "operating mineral interest" does not include royalty or similar interests (whether payable in kind or otherwise), such as production payments or net profits interests.

The Act provides a limited exception to the general rule that a "working interest" is an "operating mineral interest" which was in existence as such on January 1, 1980, in the case of working interests which have become operating mineral interests after converting from a "qualified overriding royalty interest." Production attributable to a "qualified overriding royalty interest" is eligible for reduced rates *only* after such an interest has become a working interest. (An overriding royalty generally is a nonoperating oil and gas interest which has been created out of an operating or working interest. An overriding royalty interest, generally, is separate from the usual landowner royalty.) A "qualified overriding royalty interest" is an overriding royalty interest which was in existence as an overriding royalty interest on January 1, 1980, but only if on February 20, 1980, there was in existence a binding contract under which that overriding royalty interest could be converted into an operating mineral interest. The term "qualified overriding royalty interest" also includes an overriding royalty interest which was in existence as such an interest on January 1, 1980, and converted into an operating mineral interest between that date and February 20, 1980. So long as the overriding royalty interest was in existence as such on January 1, 1980, and so long as there was a binding contract or agreement in effect on February 20, 1980, for the conversion of the overriding royalty interest into an operating mineral interest, it is irrelevant whether the conversion was mandatory or optional under the contract. In no event does production attributable to a qualifying overriding royalty interest become eligible for reduced rates prior to the time that such an interest becomes an operating mineral interest.

Transfers

Generally, reduced rates are inapplicable to production attributable to an interest (including an interest in a partnership, trust, or under a joint operating or unitization agreement) transferred after December 31, 1979. For this purpose, a transfer includes the subleasing of a lease and the conversion of a royalty or similar nonoperating interest.[10]

[10] Partnerships are not producers for windfall profit tax purposes, even though they hold the economic interest in oil. Instead, oil with respect to which a partnership holds an economic interest is treated as allocated among its partners. Each partner, then, is treated as the producer of that oil. Except to the extent provided otherwise in regulations, the allocation of the partnership's oil among its partners is determined on the basis of the partner's proportionate share of the partnership's income. (This general allocation rule is different than that applicable under Code section 613A(c)(7)(D) for purposes of computing percentage depletion.) Therefore, a shift in the amount of a partner's share of the partnership's income is a transfer for windfall profit tax purposes because it, in turn, is treated as a transfer of an interest in property held by the partnership. Production attributable to such an interest subsequent to an income shift would have to meet the tax's rules relating to transfers to be eligible for reduced rates.

Although the windfall profit tax treatment of transfers described above generally is similar to that which was used for percentage depletion purposes at the time of enactment of the Act, there are two significant differences between the two rules: (1) transfers between a producer and his or her controlled corporation do not disqualify an interest from reduced windfall profit tax rates, but disqualify an interest from percentage depletion; and (2) transfers between independent producers with 1,000 barrels a day or less do not disqualify an interest from reduced windfall profit tax rates, but do disqualify it from percentage depletion.

Under the Act, the general transfer rule denying lower rates to production from transferred interests does not apply to production attributable to a transferred interest which the transferee establishes (in accordance with regulations) was not held at any time after 1979, and before the date when it was acquired by the transferee, by anyone who was a "disqualified transferor" for any quarter ending after September 1979. A "disqualified transferor" is any person who, with respect to any quarter, (1) had qualified production in excess of 1,000 barrels a day, or (2) was not an independent producer for that quarter. For this purpose, an interest held at any time by a partnership is treated as owned proportionately by its partners at that time; an interest held by a trust or estate is treated as owned both by the entity and proportionately by its beneficiaries. Thus, in the case of a transfer by a partnership, production from the transferred interest, which otherwise met the general rules, could qualify for reduced rates only in proportion to the partnership interests held in the transferor partnership by independent producers with 1,000 barrels or less of production. For example, assume that *XYZ* partnership owned producing property *A*, and that 2 of 12 equal partners were not independent producers with 1,000 barrels or less of production. If property *A* were transferred, only 833 barrels (five-sixths of 1,000 barrels) of its production would be eligible for reduced rates; if the transferee were a partnership, each of its partners who are eligible independent producers would be eligible for reduced rates on that partner's share of the production from the property after reduction for the ineligible transferors.

If the transferee is unable to establish that the transferred interest was never held by a disqualified transferor, then production attributable to that interest is ineligible for reduced rates.

Further exceptions to the general transfer rule are provided for (1) testamentary transfers, (2) certain changes in the beneficiaries of a trust, and (3) any other transfers so long as the transferor and transferee are required to share the 1,000-barrel amount (see the definition of related parties below.) However, these exceptions apply to production from such a transferred interest *only* if the production from that interest was "qualified production" in the hands of the transferor, i.e., once an interest is disqualified under the transfer rule, it will never be eligible for reduced rates even if it is subsequently held by an eligible independent producer.

Production from an interest held by a retailer or refiner on December 31, 1979, and transferred after that date to an independent producer never qualifies for reduced rates. Similarly, production from an interest transferred after 1979 by an independent producer who, at

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any time after September 1979 and before the quarter prior to the transfer, has more than 1,000 barrels of tier one and tier two production does not qualify for reduced rates. This rule pertaining to transfers by independent producers with more than 1,000 barrels applies to production from any property transferred by such a party, regardless of whether it was owned by that person prior to, or was acquired after, the time when production exceeded 1,000 barrels.

For windfall profit tax purposes, compulsory or voluntary unitizations are not considered to be transfers if the interests resulting from the unitization are held by the same parties, and in the same proportion, as were the aggregate interests prior to unitization. However, if during the unitization process a party who had no interest in the properties obtains an interest, or a party with an interest increases it, to the extent that there is a shift in production there is a transfer as to the transferee. As such, the production qualifies only if the transfer meets the tax's requirements or is within an explicit exception.

Related parties

All related parties must share one 1,000-barrel amount. Generally, the persons who must be aggregated for purposes of this allocation are the same parties who must share one depletable quantity for percentage depletion purposes. However, a producer and a controlled corporation must share one 1,000-barrel amount. When related parties must allocate one 1,000-barrel amount, the number of barrels of production eligible for reduced rates as to any member of the related parties is reduced for each member by allocating the one 1,000-barrel amount among them in proportion to their respective qualified production for the quarter.

If a person is a member of more than one related group required to share an allocation that person's allocation must be made by reference to the related group which results in the smallest barrel allocation to that person.

Specifically, the following persons must allocate one 1,000-barrel amount: (1) members of the same family; (2) a controlled group of corporations; (3) a group of entities (including corporations, trusts, and estates) under common control; (4) producers and a controlled corporation; and (5) a family and an entity (including corporations, trusts, and estates), if 50 percent or more of the beneficial interest in such an entity is owned by the family. For purposes of the last allocation, an interest owned by or for an entity is considered to be owned directly by the entity and proportionately by its shareholders, beneficiaries, etc. Producers and a controlled corporation are required to allocate one 1,000-barrel amount if 50 percent or more of the beneficial interest in such a corporation is owned by the same producers.

Under the Act, transfers between these related parties are not subject to the general rule that prohibits the use of reduced rates for production from a transferred interest. However, this special exception remains effective only for so long as the parties are related, and only if the production was qualified production as to the transferor.

Excess production

If any independent producer's qualified production for any calendar quarter exceeds the amount subject to the reduced rates for that

quarter, the independent producer amount must be allocated among tier one and tier two oil in proportion to the person's production for that quarter of domestic crude oil in each tier.[11] The allocation of excess production is made on an overall, and not on a property-by-property, basis. Within each tier, the barrels which are deemed to be excess production in that tier must be determined by allocating among the barrels removed during the quarter, beginning with the highest removal price of those barrels. Excess production must be allocated between only tier one and tier two oil (including tier one oil which is subject to price controls).

5. Alaskan Oil

Oil from a reservoir other than the Sadlerochit reservoir that has been commercially exploited by a well north of the Arctic Circle is exempt from the windfall profit tax.[12] In addition, the Act exempts from tax Alaskan oil produced from a well which is located on the northerly side of the divide of the Alaska-Aleutian Range of mountains and at least 75 miles from the nearest point on the Trans-Alaska Pipeline System (TAPS). (This divide runs the length of the Alaska Mountains and the Aleutian Mountains and, thus, continues through the Aleutian Islands.)

Sadlerochit oil is taxed in tier one, like other upper tier oil, with two variations on the general rules. First, the adjusted base price for Sadlerochit oil may be increased to reflect any decrease in the TAPS tariff below $6.26 a barrel. The $6.26 is not adjusted for inflation. Second, the tax on Sadlerochit oil is calculated on the basis of monthly average removal prices for each producer. All other non-exempt Alaskan oil is taxed under the generally applicable rules.

6. Front End Tertiary Oil

Treatment under price controls

Under a DOE rule effective on October 1, 1979, producers who invest in enhanced oil recovery projects may be allowed to receive the market price for specified volumes of controlled oil to finance that investment. Additional revenue from the sale of this released production (the "tertiary incentive revenue") may not exceed 75 percent of certain specified expenses actually incurred for enhanced oil recovery (recoupable expenses). These expenses must be reported to DOE. Recoupable expenses are dependent upon the type of enhanced oil recovery technique that the project employs, but generally may not include the cost of hydrocarbons. No more than $20,000,000 of expenses may be recouped with respect to a particular project. However, no limitation is placed on the number of projects for which a producer may recoup expenses through the release of oil to the market price. The rule permits

[11] It was intended that the allocation of the independent producer amount between tier 1 and tier 2 be made in proportion to the relative amounts of qualified production in each tier. As enacted, the Act requires this allocation to be made on the basis of all production in those tiers. A technical correction will be needed on this point.

[12] Congress intended to exempt from tax all production from wells located north of the Arctic Circle other than those producing from the Sadlerochit reservoir on Prudhoe Bay. However, section 4994(e) fails to exempt noncommercial production north of the Arctic Circle and within 75 miles of the TAPS. A technical correction will be needed on this point.

producers to charge market prices for oil produced from properties other than the one on which the enhanced recovery project is located. Under the rule, a producer generally may receive market prices for released crude pursuant to a self-certification by the producer and a professional engineer to the Economic Regulatory Administration (ERA) that a qualified tertiary project has been undertaken, and the production would be uneconomic without the project.[13]

The Act

Oil that DOE deregulates as front-end tertiary oil is generally exempt from the windfall profit tax if the project is on a property controlled on January 1, 1980, by producers who were independent producers (as defined for purposes of reduced windfall profit tax rates) for the fourth quarter of 1979. For these projects, all of the front-end tertiary oil deregulated in connection with the project (including any produced by a major company) is exempt with two exceptions. First, oil which could have been released from crude oil price controls under any other part of the pricing rules cannot qualify for this exemption. Thus, oil removed after September 30, 1981, is not eligible for the exemption since all oil will be decontrolled after that date without regard to the front-end tertiary program. Second, oil deregulated to finance prepaid expenses cannot qualify.

If the tertiary project for which front-end oil is being deregulated is controlled by major oil companies, all front-end tertiary oil related to that project is subject to tax (including any produced by an independent producer). However, a tax refund is available for windfall profit taxes paid on the front-end tertiary oil to the extent that qualifying recoupable tertiary recovery expenditures for the project under the DOE regulations exceed the amount actually recouped under the front-end financing program. As with projects controlled by independent producers, prepaid expenses cannot qualify for the refund, nor can oil which could have been deregulated under any other price control provision.

This provision applies only to front-end tertiary oil deregulated under the August 1979 energy pricing regulations as those regulations took effect on October 1, 1979, except for changes in those regulations designed specifically to take into account the windfall profit tax itself.

A tertiary project is considered controlled by a major oil company if more than 50 percent of the operating mineral interest (taking into account only mineral interests in crude oil) in the property (or portion thereof) on which the project is being undertaken was

[13] Not all tertiary processes qualify for self-certification. The processes with respect to which the self-certification procedure is available are: (1) unconventional steam drive injection, (2) conventional steam drive injection, (3) cyclic steam injection, (4) in situ combustion, (5) microemulsion flooding, (6) alkaline flooding, (7) polymer augmented flooding, (8) miscible fluid displacement, (9) immiscible non-hydrocarbon gas displacement, and (10) any technique for the recovery of "heavy oil," as defined for price control purposes. See section 3(c), above, for the difference between the tax and price control definitions of "heavy oil." Other tertiary processes may qualify for inclusion in the program upon the producer's obtaining a DOE certification that the project uses an enhanced recovery technique which involves high levels of risks and costs.

Generally, expenditures other than those listed in the appendix to the DOE rule may be recouped only if the project is reviewed and approved by DOE.

owned, directly or indirectly, by or for major oil companies on January 1, 1980. Ownership of the front-end tertiary oil itself is irrelevant for this purpose. A major oil company is any producer who is defined as being ineligible for percentage depletion on oil and gas income because it is a retailer or refiner of oil or gas.

The Act does not allow the front-end tertiary exemption or refund for front-end tertiary oil deregulated by DOE to finance tertiary expenditures attributable to periods after September 30, 1981 (prepaid expenses). For this purpose, fuel or tertiary injectants are attributable to periods prior to October 1, 1981, if used or injected before that date. Other items are treated as attributable to periods before October 1, 1981, to the extent that income tax deductions for the item (including depreciation in respect of the item) are properly allocable to periods before October 1, 1981. Therefore, expenses paid outside the normal course of business for items which ordinarily would not be taken into account prior to October 1, 1981, are not allowed expenses for purposes of the windfall profit tax; that is, front-end tertiary oil deregulated to finance those expenses is not exempt or eligible for the refund.

However, some pre-October 1, 1981, expenditures may constitute "allowed expenses," even though they represent items completed, placed in service, or used after that date, to the extent that income tax deductions (including depreciation) are properly allocable to the item for periods before October 1, 1981. Such a determination depends upon the circumstances involved, and must be made on a case-by-case basis. For example, an expenditure could be treated as an "allowed expense" if its disbursement is in the ordinary course of business and is for a service which reasonably could be expected to be performed prior to October 1, 1981. This reasonable expectation requirement could be satisfied if such a service would have been completed prior to October 1, 1981, but for the occurrence of an event beyond the producer's control, e.g., an act of God, a severe mechanical breakdown, or an injunction. An act of God could include a strike, and injunctions could include restraining orders.

In the case of producers of front-end tertiary oil deregulated for projects controlled by major oil companies, producers are entitled to a refund of windfall profit tax previously paid on the front-end tertiary oil equal to the difference between the amount of qualifying expenses actually incurred and the amount of those expenses recouped by the release of controlled oil to the market price. Refunds would be available after September 30, 1981, for the entire period March 1, 1980, to September 30, 1981. As an alternative to obtaining a tax refund, these producers may adjust their tax withholding for taxable periods after September 30, 1981, in a manner prescribed by regulations.

7. Taxable Person

General rules

The Act generally imposes the windfall profit tax on the first sale of taxable crude oil and requires payment of the tax by the producer. The tax is to be withheld by the first purchaser of the oil and deposited with the Treasury, except as otherwise provided in Treasury regulations. The Act defines the producer as the owner of the economic

interest in the oil and thus places the burden of the windfall tax on the persons who will receive the increased income resulting from decontrol and OPEC price increases. Whether a particular taxpayer is the owner of an economic interest in the oil is determined under the same rules that apply for Federal income tax purposes.

Partnerships.—In the case of a partnership that owns an economic interest in taxable crude oil, the tax is imposed directly on the partners on their proportionate share of the partnership's production.

For purposes of applying Subchapter K, the windfall profit tax is not to be treated as a partnership deduction, but any amount withheld from the partnership by a purchaser shall be treated as a distribution of money by the partnership to the partner.

Production payments.—In the case of the production of oil which is subject to a production payment, the windfall profit tax is imposed on the owner of the economic interest as determined under Federal income tax provisions (sec. 636). (A production payment is a right to a specified share of production (or a sum of money in lieu thereof) from a mineral property when that production occurs. The payment generally is secured by an interest in the mineral, constitutes a right to production for a period of time that is less than coextensive with the anticipated life of the property, bears no production costs, and may be subject to a stated or unstated interest rate. Most types of production payments are treated as loans under Code section 636 and do not qualify as economic interests in a mineral property.) No special provisions are made for production payments under the windfall profit tax because production payment contracts usually provide for an automatic adjustment to reflect the imposition of additional severance taxes such as the windfall profit tax.

No exemptions.—The Act provides specifically there are no exemptions for persons or oil unless provided explicitly in the Crude Oil Windfall Profit Tax Act of 1980 or future legislation. In the event that the legislation conflict is with any treaty obligations of the United States, Congress intends that the legislation prevail.

State and local governments

The Act provides that if an economic interest in crude oil is held by a State or political subdivision thereof, or by an agency or instrumentality of any of the foregoing, and all of the net income received pursuant to such interest is dedicated to a public purpose, then the windfall profit tax will not be imposed with respect to crude oil properly allocable to such interest. For this purpose, the term "net income" means gross income from the property reduced by production costs and severance taxes of general application. A severance tax of general application is one imposed at a uniform rate on all owners of rights in oil production, both public and private. The exemption would not apply to the extent another party had an economic interest in the production.

Federal royalty oil, including oil production from a National Petroleum Reserve and royalties from Federal leases, is subject to tax (see section two above).

Qualified educational institutions and medical facilities

Oil produced from economic interests held by charitable medical facilities and educational institutions is exempt from the windfall

profit tax if the interests were held by the medical facility or educational institution on January 21, 1980 and at all times thereafter before the last day of the calendar quarter in which the oil was removed. For purposes of the exemption, a medical facility is defined as an organization the principal purpose or function of which is the providing of medical or hospital care or medical education or, if in conjunction with a hospital, medical research (see Code section 170(b)(1)(A)(iii)). For purposes of the exemption, an educational institution is an educational organization that normally maintains a regular faculty and curriculum and normally has a regularly enrolled body of pupils or students in attendance at the place where its educational activities are regularly carried on (see Code section 170(b)(1)(A)(ii)). An organization that normally receives a substantial part of its support from the United States or any State or political subdivision thereof or from direct or indirect contributions from the general public, and that is organized and operated exclusively to receive, hold, invest, and administer property and to make expenditures to or for the benefit of a public college or university is also considered to be an educational institution (see Code section 170(b)(1)(A)(iv)). In addition, oil produced from interests held by a church on January 21, 1980, is exempt from the tax only if prior to January 22, 1980, the net proceeds from production of such oil were dedicated to the support of a medical facility or educational institution. Production from an interest in oil received, as a bequest or otherwise, after January 21, 1980, is not eligible for the exemption.

Indian oil

The Act exempts from tax certain oil production from mineral interests held by or on behalf of Indian tribes or individual Indians on January 21, 1980. Specifically, the exemption applies to three types of oil production that generally also are exempt from Federal income taxation. First, production received by Indian tribes and individuals from Tribal Trust Lands held in trust on January 21, 1980, will not be taxed. Tribal Trust Lands are lands and mineral interests title to which is held by the United States in trust for Indian tribes or their members. Secondly, oil produced from lands or mineral interests held on January 21, 1980, subject to Federally imposed restrictions on alienation, by a recognized Indian tribe or by members of a recognized tribe, is exempt from the tax. A recognized Indian tribe is one that is eligible for services provided by the Secretary of the Interior to Indians. Thirdly, the exemption applies when the proceeds from the sale of oil are paid into the U.S. Treasury to the credit of tribal or native trust funds pursuant to provisions of law in effect before January 22, 1980. The Act does not exempt oil received by non-Indian lessees of tribal interests, by tribes or tribal organizations over which trust responsibilities have been terminated by the United States, or by individual Indians or tribes from unrestricted lands.

An exemption also applies to the oil production of any Alaska Native Corporation organized under the Alaska Native Claims Settlement Act from interests received pursuant to that Act if the oil is produced prior to 1992, when the stock of such corporations may be traded.

8. Taxable Income Limit

The windfall profit on a barrel of oil may not exceed 90 percent of the net income attributable to the barrel. In applying this limitation, the net income attributable to a barrel is determined for the taxable year by dividing the taxable income from the property which is attributable to taxable crude oil by the number of barrels of that oil produced from the property during the taxable year. In computing net income for this purpose, taxable income from the property is determined under section 613(a) (relating to percentage depletion) but without any deductions for depletion, intangible drilling and development costs under section 263(c) (except the costs of drilling a dry hole), and the windfall profit tax. For this provision, "property" has the meaning given to it in section 614, not in the price control regulations, and costs on properties producing both oil and gas are allocated under the rule generally applicable for percentage depletion purposes. (See section 613A(c)(7)(C).) In the case of partnerships, the computation of the net income limitation is made by each partner rather than the partnership.

The Act further provides that, in determining the 90-percent limit, the producer's taxable income from the property is to be reduced by the deduction for cost depletion which would have been allowable if all intangible drilling costs incurred by the taxpayer with respect to the property (other than those incurred in drilling a nonproductive well) had been capitalized and taken into account in computing cost depletion, and if the producer had used cost depletion for the property for all periods during which he owned his economic interest in the property (even if he had actually used percentage depletion on his income tax return). In effect, producers using percentage depletion must compute an imputed cost depletion deduction. However, if a producer actually capitalizes intangible drilling costs for income tax purposes, he may reduce his taxable income from the property by the amount deductible under section 611 of the Internal Revenue Code in connection with those costs (either as cost depletion or depreciation) instead of assuming that all those costs were deducted as cost depletion.

In addition, the Act provides that for purposes of the 90-percent net income limitation, the producer may elect to treat qualified tertiary injectant costs (as described below in the section on Business Energy Tax Incentives) as if they had been capitalized and recovered through cost depletion. This election would be made in the year injections are first made on a property.

The Act provides a special rule for determining the taxable income limit in the case of certain transfers of proven oil or gas properties after 1978. If a transfer of a proven property would result in an increase in the amount by which a transferee producer's taxable income could be decreased by virtue of a larger actual or imputed cost depletion deduction, the Act provides that the transferee producer may compute the cost depletion deduction (for purposes of the 90-percent limit) on only those amounts which would have been allowable to the transferor plus costs incurred by the transferee during periods after the transfer of the property. For purposes of this rule, a proven

property is given the same meaning as that applicable to the Internal Revenue Code's limitation on the allowance for percentage depletion in the case of oil. This rule applies to any post-1978 transfer, including the creation of a production payment which results in the transfer of an economic interest, and leases and subleases of an interest (including an interest in a partnership or a trust) in any proven oil or gas property.

If any portion of the taxable crude oil removed from the property is applied in discharge of a production payment, the gross income from such portion must be included in the gross income from the property in computing the taxable income of the producer (for purposes of the 90-percent limit). Thus, that amount of gross income will be taken into account in computing the taxable income limits of two persons—the creator of the production payment and the owner of it.

9. General Tax Computation Rules

Determination of selling or removal price

The term "removal price" generally means the amount for which the barrel of oil is sold. The Act provides special rules for determining the removal price when oil is removed from the premises prior to sale and when refining is begun prior to the oil's removal. If crude oil is removed from the premises before it is sold, the removal price is the constructive sale price used in determining gross income from the property under section 613 (relating to percentage depletion). If the crude oil's conversion or manufacture into refined products begins before the oil is removed from the premises, the oil is treated as removed on the day when manufacture or conversion begins, and the removal price is the constructive sale, or representative field, price at the time of removal of the oil from the property for depletion purposes. For purposes of determining the removal price, the terms "premises," "refined product," and "constructive sales," or "representative field," price have the same meaning as when used in determining gross income from the property for depletion purposes. Thus, oil returned to the property from which it came, either by reinjection or through the powering of production processes or equipment, is not considered sold or removed from the premises. For example, no tax would be imposed on the on-site use of such powerhouse oil to generate power for an artificial lift device, or water flood project, or a tertiary injection process. However, oil removed from the property prior to its use, or oil used to power refining or manufacturing processes would be taxed.

Due to differences in the definition of the word "property," a producer could have a single, undivided piece of land which constitutes many DOE "properties," even though they are contiguous and not even divided by a public road. In such a case, "powerhouse" fuel produced on one section of a single undivided piece of land is not taxable if it is used on another section of the same piece of land as powerhouse fuel and never leaves the piece of land on which it is produced. This windfall profit tax treatment of such oil has no implication for its treatment for various income tax purposes.

Under the Act, the rules for determining the constructive removal price also apply in the case of sales of crude oil between related per-

sons. For this purpose, the term "related person" has the same meaning as it does for purposes of the small issue exemption from the limitation on the issuance of tax exempt industrial revenue bonds (sec. 103(b)(6)(C)). Under this definition, persons are related if losses would be disallowed on exchanges between them under section 267 or section 707(b), or if they are members of the same controlled group of corporations (under sec. 1563(a)). In the latter case, the rules for determining membership in a controlled group apply with the exception that "more than 50 percent" is substituted for "at least 80 percent" in the common ownership of voting control or value tests. (See below for a discussion of administrative enforcement rules applicable to all taxpayers.) These rules for determining constructive sales prices for sales between related persons give the Secretary the authority to make appropriate adjustments to actual selling prices.

Under the existing administrative practices relating to the determination of a constructive sale price, the Internal Revenue Service may determine such a price for oil when transactions occur between persons under common control. In the past, taxpayers may have sought to increase the size of their depletion deduction by means of artificial transactions. In such an instance, the determination of a constructive sale price has reduced the amount of gross income from the property for depletion purposes. If the oil is sold for an artificially low price, the windfall profit tax would be imposed on the higher constructive sale price.

The Act also allows the Secretary to adjust prices in transactions between unrelated parties when such an adjustment is needed to make the removal price reflect the fair market value of the oil. For example, if the producer gives the purchaser a discount for paying for the oil in advance, the removal price could be adjusted up to the fair market value without the discount.

Treatment of State severance taxes

Various States impose severance or production taxes on the extraction of oil. These taxes are imposed either on each unit of production as a fixed fee per barrel or as a percentage of the value of each barrel.

Severance taxes generally are imposed on the owners of the various interests in a property (i.e., the operator, other investors, royalty owners, etc.). However, the taxes normally are paid by the first purchaser of the oil, who withholds the tax from the amount paid to the holder of the interest upon whom the tax is imposed. For Federal income tax purposes, the amount of severance taxes is included in the producer's or royalty owner's gross income from the property, and an offsetting deduction for the severance tax is permitted.

Generally, under the Act there is a deduction in computing the taxable windfall profit for the State severance taxes imposed on the windfall profit element of the price of a barrel of oil—the difference between the selling price and the adjusted base price.

For this purpose a State severance tax is defined as a tax on the removal of crude oil from the ground, levied by a State, but not by a political subdivision of a State, as a percentage of the gross value of the crude oil removed. Any State tax that meets this definition, regardless of its official name or title, is treated as a severance tax. A tax levied on

the value of reserves or on the basis of net proceeds from production is not a severance tax. Although a tax on the removal of crude oil from the ground levied as a fixed fee per barrel generally is considered a severance tax, the formula for calculating the severance tax adjustment in the Act would not result in an adjustment for such a tax because the amount of that tax would be the same whether levied on the adjusted base price or on the removal price of a barrel of oil. Thus, a tax levied as a fixed fee per barrel is not considered a severance tax for purposes of the windfall profit tax.

Post-March 31, 1979, increases in the rate of severance tax can be taken into account only if the increase applies to the entire price of a barrel of oil. The fact that a State severance tax does not apply to a particular type of oil, such as royalty oil paid to the Federal or State Government or newly discovered oil, does not affect the availability of the severance tax adjustment, as long as the severance tax applies to the entire price of those barrels which are subject to tax.

A severance tax may not be taken into account to the extent the total rate of severance tax imposed by a State exceeds 15 percent. The conversion of a non-qualifying tax, such as a severance tax levied as a fixed fee per barrel, into a tax levied as a percentage of the gross value of oil removed constitutes an increase in the severance tax on the windfall profit element of the selling price. Thus, such a conversion would have to satisfy the limits on post-March 1979 increases in State severance taxes before a severance tax adjustment would be available with respect to such a converted tax.

Inflation adjustment

The Act provides that the inflation adjustments required by the tax are to be computed by using the GNP deflator. The GNP deflator, that is, the implicit price deflator for the gross national product, measures inflation in domestically produced goods and services.

Under the Act, the inflation adjustment to the base prices for any calendar quarter is the percentage by which the GNP deflator for the second preceding calendar quarter exceeds the GNP deflator for the second calendar quarter of 1979. The first such adjustment occurs, therefore, for the first quarter of 1980. This two-quarter lag in measuring the inflation adjustment is necessary because of the lapse of time before the data become available. The DOE inflation adjustments to the lower and upper tier ceiling prices have a similar lag in the adjustment.

In all cases, the first revision of the GNP deflator, which becomes available in the third week of the second month following the close of the quarter, is to be used in determining the inflation adjustments.

The inflation adjustment used to derive an adjusted base price under the Act may be expressed as a formula:

$$B_i = B_0 \left[\frac{P_{i-2}}{P_{1979.2}} \right]$$

where B_0 is the original base price for the property, B_i is the adjusted base price in the ith calendar quarter after the fourth quarter of 1979 (i.e., i=1 for 1980. 1, i=2 for 1980. 2, etc.) and P_i is the GNP deflator for the ith quarter.

For tier 3 oil, the inflation adjustment is increased by a 2-percent annual kicker, so that the appropriate formula would be:

$$B_i = B_0 \left[\frac{P_{i-2}}{P_{1979.2}} \right] 1.005^{\,i}$$

10. Regulatory Authority

The Act authorizes the Secretary of the Treasury to prescribe such regulations as may be necessary to carry out the purpose of the tax. The windfall profit tax is based on several concepts used in the energy regulations, and the Secretary may prescribe regulations which interpret how the energy regulations are to be applied for the windfall profit tax. This regulatory authority is essentially the same as the authority which the Secretary generally has with respect to tax legislation. Congress does not anticipate that major changes in the energy regulations will be needed to apply them for tax purposes, but it intends that references to energy regulations in the Act are not to be interpreted as denying the Secretary the usual regulatory authority.

Generally, the Act adopts various energy regulations in effect on specified dates to implement the tax. In addition, the Act provides that the energy regulations adopted for tax purposes are to be treated as being effective without regard to decontrol of oil prices or any other termination of their application or any changes in those regulations by DOE. Reference to the energy regulations also would be important when the Secretary or producers must make determinations by analogy to the energy regulations, *e.g.*, computing the base level for a tertiary project.

The Act grants the Secretary broad authority to prescribe regulations needed to implement and administer the tax. In some instances, e.g., as to independent producers, this authority relates to formulating windfall profit tax rules similar to income tax rules, and in other instances, e.g., as to production from unitized properties, it relates to providing windfall profit tax rules analogous to those contained in the energy regulations. For example, it is anticipated that the Secretary will issue "hold harmless" regulations with respect to production from unitized properties. Such regulations may adopt or modify, where appropriate, unitization rules established for price control purposes. Additional unitization rules may be necessary for the effective implementation of the tax, such as in those instances where the windfall profit tax and regulatory treatment of a particular type of oil differ. Unitization rules will be needed also to make sure that the reduced rates for independent producers do not discourage unitization.

11. Definitions

Crude oil.—The definition of crude oil for windfall profit tax purposes is fixed by the June 1979 energy regulations. Therefore, the term "crude oil" means a mixture of hydrocarbons which exists as liquids in underground reservoirs and which remain liquid at atmosphere pressure after passing through surface separating facilities. The term also includes condensate recovered in associated or nonassociated production by mechanical separators located at any point at or before the in-

let side of a gas processing plant, and natural gas liquid treated as crude oil under the June 1979 energy regulations. The term "crude oil," however, does not apply to synthetic petroleum such as oil production from shale or tar sands.

Barrel.—The term "barrel" means 42 United States gallons.

Domestic.—When used in reference to crude oil, the term "domestic" means crude oil produced from an oil well located in the United States, or in a possession of the United States.

United States.—The term "United States" when used in a geographical sense includes the seabed and subsoil of the submarine areas adjacent to territorial waters of the United States over which the United States has exclusive rights under international law to explore for and exploit natural resources. This is the same meaning given the term, "United States" by paragraph (1) of section 638 of the Internal Revenue Code (relating to Continental Shelf areas).

Possession of the United States.—The term "possession of the United States" when used in a geographical sense includes the seabed and subsoil of the submarine areas adjacent to the territorial waters of the possession over which the United States has exclusive rights under natural law to explore for and exploit natural resources. This is the same meaning given the term "possession of the United States" by paragraph (2) of section 638 of the Internal Revenue Code (relating to Continental Shelf areas).

Energy regulations.—The term "energy regulations" means crude oil price control regulations prescribed under section 4(a) of the Emergency Petroleum Allocation Act of 1973, as amended. Energy regulations, for windfall profit tax purposes, are treated as continuing in effect without regard to decontrol of oil prices or any other termination of the regulations. The "March 1979 energy regulations" are the terms of the energy regulations as the terms existed on March 1, 1979. The "June 1979 energy regulations" are the terms of the energy regulations as the terms existed on June 1, 1979.

Generally, the terms "energy regulations," "March 1979 energy regulations" and "June 1979 energy regulations" freeze the terms of those regulations as of the applicable date. As a result, those terms do not include subsequent administrative, executive, or judicial action or interpretations. For example, DOE Exceptions Relief actions are not taken into account regardless of whether they were finalized before or after June 1, 1979, because they are temporary actions subject to periodic review. Similarly, post-June 1979 judicial interpretations of those regulations, *e.g.*, *Tenneco* v. *FEA*, 596 F.2d 1029 (TECA 1979), are not included in their terms for windfall profit tax purposes, although the Secretary may give such interpretations due consideration.

With one exception, the terms of the June 1979 energy regulations were frozen as they existed on June 1, 1979. Under the one exception, the June 1979 energy regulations are treated as including action taken under the terms of those regulations before, on, or after June 1, 1979, with respect to incremental production from particular qualified tertiary enhanced recovery projects. Because the application of the June 1979 energy regulations to such projects was supplanted by the DOE regulations issued in August 1979, this one exception applies only to incremental production from projects certified by DOE under the June 1979 energy regulations prior to their change.

Rulings issued by DOE or its predecessors generally are of an interpretive nature and, as such, are not "final action[s]" taken under the June 1979 energy regulations or binding on the courts or the Secretary. In this regard, energy rulings simply are comparable in effect to Revenue Rulings.

Operator.—The term "operator" means the person or persons designated, in accordance with regulations, as operator of a property or portion thereof, by the holders of the operating mineral interests in the property. Such a designation applies only for windfall profit tax purposes. If the producers make no such designation, the operator is the party or parties primarily responsible for management and operation of production from the property. This may be one of the owners of the property or a third party who manages the property under a contractual agreement with its owners.

Producer.—The term "producer," unlike its definition under the energy regulations,[14] means only the holder of the economic interest with respect to the crude oil. Whether a particular taxpayer is the owner of an economic interest in oil is determined under the same rules that apply for Federal income tax purposes. The one exception to this tax definition arises in the case of crude oil with respect to which a partnership holds the economic interest. In such a case, the partnership's crude oil is allocated among its partners, generally on the basis of each partner's proportionate share of the partnership's income. Each partner then is treated as the producer of the oil so allocated.

Property.—The meaning of the term "property" depends upon the section and context in which it is used. Generally, the word property has the same meaning as that term is given by the energy regulations. Therefore, "property" generally means either (1) a right to produce domestic crude oil that arises from a lease or fee interest, or (2) at the election of the producer, separate and distinct producing reservoirs that are subject to the same right to produce and that are recognized as separate and distinct reservoirs by the appropriate government regulatory authority.

In some instances, however, the word "property" has the meaning given to it by section 614 of the Code. For example, the section 614 definition of the term property is used for purposes of (1) the 90-percent-of-net income limit on the taxable windfall profit and (2) determining whether a person has a "working interest" in a property for purposes of the reduced rates available to independent producers.

12. Administrative Provisions

For administrative purposes, there are two general categories into which crude oil falls: oil subject to withholding and oil not subject to withholding. Except as otherwise provided in Treasury regulations,

[14] Under the energy regulations, the term producer means a firm or that part of a firm which produces crude oil or natural gas, or any firm which owns crude oil or natural gas when it is produced. 10 C.F.R. sec. 212.31. This energy definition, thus, includes such diverse parties as crude oil reclaimers who have no economic interest in the producing property. See *Tesoro Petroleum Corp.*, 2 FEA par. 80,514 (1975).

the first purchaser of domestic crude is required to withhold the windfall profit tax from amounts payable to the producer of the oil and deposit those amounts with the Treasury. When withholding is not required, the producer is required to pay the tax with respect to its own production.

Responsibilities of operator.—In the case of oil subject to withholding, the operator normally must certify to the first purchaser the information which the purchaser needs to compute the tax. This includes the tier in which the oil is taxed, the adjusted base price of the oil, the amount of oil, any certification furnished to the operator by the producer with respect to whether such oil is exempt oil or oil subject to reduced rates for independent producers, and any other information required by regulations.

For windfall profit tax purposes, the operator is the person primarily responsible for the management and operation of the crude oil production. However, to the extent provided in regulations, persons holding the operating mineral interests in the property can designate another person (or persons) as the operator.

Except as otherwise provided in regulations limiting the election, the operator and the first purchaser may elect to have the operator assume the purchaser's responsibilities under the tax. If such an election is made, unless the operator is a major oil company, the operator must deposit the withheld tax (or estimated tax) at the same time the purchaser would have had to make deposits or estimated tax payments. Thus, if the purchaser is an integrated oil company, the deposit and estimated tax rules for integrated companies will apply to the operator.

In the case of oil not subject to withholding, the operator is required to certify to the producer the tier in which the oil is taxed, the adjusted base price for the oil, the amount of oil, and any other information required under regulations. The operator and producer may elect, in accordance with regulations, to relieve the operator of this obligation.

Responsibilities of purchaser.—In the case of oil subject to withholding, the first purchaser must withhold the windfall profit tax from the amount payable by such purchaser to the producer of the oil. The purchaser is liable to the IRS for the payment of the amount required to be withheld and is not liable to the producer for that amount. The amount withheld is to be determined on the basis of the certification provided by the operator (including any certification that part or all of the production is eligible for the reduced rates for oil produced by independent producers), and the purchaser is not responsible for errors in withholding resulting from improper certification unless it has reason to believe the certification is improper. If no certification is provided or if the first purchaser has reason to believe that the information contained in the certification is incorrect, then the amount withheld must be determined under regulations prescribed by the Secretary. To encourage the furnishing of information, these regulations may require withholding of the maximum possible tax on any particular oil even though such tax exceeds the amount that would have been due if a proper certification had been made.

The first purchaser is required to file quarterly returns showing the amount of tax withheld, together with any other information required

under regulations. The first purchaser's quarterly return for the fourth quarter is to be filed before March 1 of the following year. The first purchaser's information statement will provide each producer with information indicating the amounts of oil purchased and the tax withheld thereon. In the case of oil purchased from a partnership, the purchaser will provide information with respect to the partnership's oil. The partnership's return will provide information with respect to each partner's share of the production.

The timing of the obligation of any first purchaser to deposit amounts withheld depends upon the identity of the first purchaser. Major refiners and retailers, i.e., those parties described in section 613A(d)(2) and (3), other than independent refiners, are required to make semimonthly estimated deposits of the withholding tax. All other first purchasers are required to make withholding deposits not later than 45 days after the close of the month in which the oil is removed from the premises, except that independent refiners who purchase oil under delayed payment contracts are required to make deposits by the first day of the third month beginning after the month of the removal. Failure to make timely deposits will result in the generally applicable penalties. However, estimated tax deposits which meet "safe harbor" levels, similar to those contained in Treasury regulation § 48.6302(c)–1 (relating to deposits of excise taxes generally), would prevent the imposition of penalties.

If the first purchaser withholds an incorrect amount of tax on any oil, adjustments in withholding are required to correct the aggregate amount withheld on all oil purchased by that purchaser from the producer on oil removed during that calendar year. The amount of such mandatory adjustments in withholding taxes payable to the Treasury may not exceed the amount of the windfall profit on any barrel of oil removed.

Required withholding adjustments apply only with respect to transactions between the same purchaser and producer. However, a producer may voluntarily authorize any purchaser to withhold with respect to oil removed later in the calendar year to correct earlier withholding errors. Such an amount is to be treated as an amount required to be withheld such that the deposit and return filing rules will apply. In addition, the Secretary may allow, under regulations, withholding adjustments after the close of the calendar year.

Increases in posted prices after the initial determination of the removal price also increase the windfall profit, and hence the tax. In such a case, the tax attributable to the price increase must be withheld.

Responsibilities of producer.—Generally, there is no requirement that producers of oil that is subject to withholding file a windfall profit tax return if the correct amount of tax is withheld for the year.

In the case of withheld oil, the producer is deemed, for windfall profit tax purposes, to have paid, on the last day of February of the year following that in which the oil was removed, the amount of tax withheld by the purchaser.

Producers are required to deposit the tax due on their own production not subject to withholding in the same manner they would deposit tax withheld by them if they were first purchasers. In other words,

major companies make deposits of their estimated tax liability twice a month and all other producers deposit the tax within 45 days after the month of removal.

Oil produced by producers who are entirely exempt from the windfall profit tax by virtue of the provisions exempting certain State, Indian, or charity's oil is not subject to withholding if an appropriate certification is given to the first purchaser.

Producers exempt from all or a portion of the tax by virtue of the net income limitation may file for a refund after the close of the year. They are not entitled to file a withholding tax exemption certificate, or use the withholding adjustments to take the 90-percent limit into account.

Statute of limitations.—In the case of oil subject to withholding for which no windfall profit tax return is required from the producer, the statute of limitations for purposes of claiming a refund or assessing a deficiency runs with respect to the producer's annual income tax return for the taxable year in which calendar year of the oil's removal ends. In the case of a Federally registered partnership, the Secretary may prescribe limitation rules similar to the rules applicable to income tax returns.

If the Department of Energy makes a final determination reclassifying oil for pricing purposes under the June 1979 energy regulations, then the statute of limitations for assessing any deficiency or for filing a claim for a windfall profit tax refund attributable to such DOE reclassification will not expire before one year after the redetermination becomes final.

The Act further provides the Secretary with authority to prescribe administrative regulations consistent with the specific provisions of the tax, including any pertaining to information exchanges and returns (e.g., reporting windfall profit tax items on existing excise tax, income tax, and information returns).

Interest.—Interest on the overpayment of tax by a producer with respect to withheld oil will run from the last day of February of the year following the removal year. However, if the IRS refunds the windfall profit tax overpayment within 45 days after the later of (1) the unextended due date of the windfall profit tax return (or if no return is required, the income tax return for the taxable year in which the removal year ends) or (2) the date the return is filed, then no interest shall be allowed.

13. Interaction With Income Tax

The Act provides producers with a deduction from gross income in determining Federal income taxes for windfall profit tax. The deduction is allowable for the taxable year with respect to which the tax actually is paid or accrued.[15]

[15] Code section 4995(a)(4)(B) treats any amount withheld as having been paid by the producer on the last day of February of the calendar year following the year in which the oil was removed. This rule is solely for purposes of administration of the windfall profit tax and is not intended to affect the timing of income tax deductions.

14. Court Jurisdiction

The Act grants the United States Tax Court prepayment jurisdiction over windfall profit tax deficiencies. This jurisdiction does not include the determination of liability under the withholding provisions of the tax.

Because the tax is imposed with respect to a producer's crude oil removed during a calendar quarter, the scope of a deficiency or refund suit is with respect to the tax for the entire quarter. Thus, a second suit may not be brought with respect to the same quarter, and in the case of a refund suit, the entire tax assessed with respect to that quarter must be paid.

15. Effective Date

The provisions of the Act generally apply to oil removed after February 29, 1980. For the period ending June 30, 1980, the Secretary may prescribe rules relating to the administration of the tax which may supplant or supplement the rules in the Act.

16. Termination of Tax

Under the Act, the tax phases out during a 33-month period by reducing each producer's tax by 3 percent for each month starting with the later of January 1988 or the first month (but not later than January 1991) after that for which the Secretary estimates that the aggregate net windfall profit tax revenue will permanently exceed $227.3 billion (excluding tax on oil owned by the United States).

For purposes of estimating the amount of tax received by the Treasury, the Secretary first must estimate the gross windfall profit tax receipts, minus any revenue attributable to economic interests in crude oil held by the United States. This figure then is reduced by windfall profit tax refunds, but not by administrative costs or deficiencies attributable to the windfall profit tax. It is reduced further by estimated Federal income tax reductions for producers that result from deductibility of the windfall profit tax and any other change in income taxes arising from the windfall profit tax. In estimating the reduction for windfall profit tax refunds and income tax deductions, the Secretary is to take into account those items which properly are attributable to preceding taxable periods even though they actually have not been refunded, or used to reduce income taxes, at the time of the estimate.

Starting with January 1987, the Secretary must make monthly estimates of the cumulative net windfall profit tax revenue raised.

17. Study of Decontrol and Tax

The President is required to submit a report to the Congress no later than January 1, 1983, on the effect of decontrol and the windfall profit tax on (1) domestic oil production; (2) oil imports; (3) oil company profits; (4) inflation; (5) employment; (6) economic growth; (7) Federal revenues; and (8) national security. This report is to be accomplished by such further energy related legislative recommendations as the President may care to make.

18. Disposition of Windfall Profit Tax Revenues

The Act provides that the net revenues from the windfall profit tax are allocated only for the specific purposes described below to a separate account at the Treasury (for accounting purposes only). They shall not be earmarked or invested separately from general revenues, however. Net revenues from the windfall profit tax are equal to the gross amount of windfall profit tax collected (other than from oil owned by the United States) minus the reduction in income tax receipts resulting from imposition of the windfall tax.

The net revenues projected under current assumptions from 1981 through 1990 are allocated for the following specific purposes—

(a) *Aid to lower income households.*—25 percent of net revenues. For fiscal year 1982 and subsequent years, these funds would be divided equally between a program to assist AFDC and SSI recipients under the Social Security Act and a program of emergency energy assistance.

(b) *Individual and corporate income tax reductions.*—60 percent of net revenues. This would include tax cuts to help taxpayers cope with higher energy prices.

(c) *Energy and transportation spending programs.*—15 percent of net revenues.

Of the net revenues in excess of what is projected under current price assumptions (and shown in table 4), one-third is allocated for aid to lower income households, without specification of type of program, and two-thirds is allocated for income tax reductions. Any outlays by the Synthetic Fuels Corporation are to be financed from increases in general revenues resulting from decontrol. There is no specific allocation for the Corporation because its outlays will be very uncertain in timing and amount.

The President is required to propose, for each fiscal year after fiscal year 1980, allocation of net revenues from the windfall profit tax among the purposes specified above. For fiscal year 1981, the proposal was to be submitted within 90 days after enactment; for succeeding fiscal years, the proposal must be contained in the annual budget. The Secretary of the Treasury will report annually to Congress, beginning in fiscal year 1982, on the net revenue derived from the windfall profit tax for the preceding fiscal year and the actual disposition of these revenues among the purposes specified above.

Further legislation is needed to use the money raised by the tax for any of the purposes specified above. Failure to enact such legislation, of course, would mean that the revenue from the tax would have the effect of reducing the Federal deficit.

B. RESIDENTIAL ENERGY CREDITS

(Secs. 201–3 of the bill and sec. 44C of the Code)

Prior Law

Insulation and other energy conserving items

A 15-percent credit on the first $2,000 of qualifying expenditures, a maximum credit of $300, is available for expenditures made after April 19, 1977, and before January 1, 1986, for installations of eligible insulation and energy conserving items. Installations must be made in or on a taxpayer's principal residence. The residence must have been in existence or substantially completed on April 19, 1977. The $2,000 maximum on allowable expenditures is the total amount available to the taxpayer for any principal residence through December 31, 1985. This limit will be reduced each year by expenditures for which the energy conservation credit was taken in prior years by that taxpayer for that residence.

The credit is allowed for expenditures to install (1) insulation, (2) a replacement burner for an oil- or a gas-fired furnace, (3) a device to modify flue openings, (4) an electrical or mechanical furnace ignition system, (5) a storm or thermal door or window, (6) an automatic setback thermostat, (7) caulking or weatherstripping for an exterior door or window, and (8) a meter that displays the cost of energy use.

Authority was given to the Secretary of the Treasury to add other qualifying items to the list of property eligible for the credit.

Renewable energy source property

A tax credit equal to 30 percent of the first $2,000 of eligible expenditures and 20 percent of the next $8,000 of eligible expenditures, a maximum credit of $2,200, was allowed for expenditures made after April 19, 1977, and before January 1, 1986, for installation of (1) solar, (2) wind, or (3) geothermal energy equipment. Installations must be made in connection with a taxpayer's principal residence. The $10,000 maximum on allowable expenditures is the total amount available to the taxpayer for any one principal residence through December 31, 1985. This limit is reduced each year by expenditures for which the renewable energy source credit was taken in prior years for the same residence.

The Secretary of the Treasury was given the authority to add renewable energy sources to the list of sources for which equipment is eligible for the credit.

General provisions applicable to residential energy credits

Any increase in basis of the residence which would otherwise result from the energy conservation expenditures must be reduced by the amount of the credit which the taxpayer has claimed with respect to

the expenditures. For example, if a taxpayer made $10,000 of qualified renewable energy source expenditures, the basis increase would be only $7,800 if a $2,200 credit had been allowed for the expenditures.

Taxpayers are eligible for the maximum credit for each principal residence they may occupy while the credit is available. Owners or tenant-shareholders of condominiums and cooperative housing are eligible for the credit on their proportionate shares of qualified expenditures. The credit is available to renters as well as homeowners. Joint occupants of a principal residence also may claim the tax credit for their respective shares of qualified expenditures. Prior law, however, did not directly refer to cases in which owners or renters of several principal residences jointly own eligible energy conservation property.

The Secretary of the Treasury is authorized to issue regulations which specify performance and quality standards for each item.

If the credits exceed tax liability for any year, the credits may be carried over to subsequent years through 1987, i.e., 2 years after expiration of the credit.

Reasons for Change

Congress reviewed the provisions for residential energy credits in prior law to assess their effectiveness in increasing efficient energy usage and in reducing reliance on oil and gas as fuel.

Congress concluded that prior law may not have provided taxpayers with a broad enough range of alternative equipment for reducing fuel costs. Congress recognized, however, that it did not possess the resources with which to judge the merits of every specific conservation device. It also was concerned that the Secretary of the Treasury may not have made sufficient use of the discretionary authority to add additional energy conservation items or renewable energy sources to the lists of eligible equipment and sources because Congress in 1978 did not provide specific standards for the Secretary to apply in making decisions. To resolve this situation, Congress in this Act established a set of specific criteria that the Secretary will use in determining whether property could qualify for the residential tax credits. These standards will make it easier for the Secretary to make decisions about what should or should not be added. It is expected that the Secretary will evaluate certain specific energy conserving items, including efficient replacement furnaces and efficient wood stoves if the appropriate information is filed with the Secretary in a timely manner.

Congress also was concerned that the various tax, loan and grant subsidy programs which Federal, State and local governments have enacted could be combined in a way that would enable a taxpayer to purchase energy conserving property with little or no expenditure of his own funds. As a result, the overall efficiency of the economy might be reduced because compounded subsidies would divert resources from their most efficient productive uses. Thus, the Act contains rules which, in conjunction with the prior treatment of nontaxable grants, require, in effect, that the purchaser of eligible equipment choose between the tax credit, on the one hand, and subsidized energy loans or nontaxable grants on the other hand.

Congress was also concerned about the slow commercialization of renewable energy sources. These are often unfamiliar to potential pur-

chasers and must compete with energy sources whose use is subsidized by price controls.

A larger credit for new installations of renewable energy source property will stimulate both the demand and supply sides of these industries. A substantial increase in the credit will induce more people to incur the costs of installing one of these new systems and may provide persuasive evidence to other individuals that it pays to install a new, renewable energy source system.

Manufacturers of renewable energy source systems and the essential component parts and the distributors and retailers who install and service the systems will receive encouragement from the effect of a larger credit in sustaining and expanding the size of the market.

The review of the types of renewable energy source systems indicates that the major heating and cooling systems are covered under present law. However, solar and geothermal energy may also be used as part of a system to generate and store electricity for use in the residence. In both cases, the electricity may be used directly as it is generated or stored for later use. These uses of renewable energy sources are also appropriate things to encourage with the residential energy tax credit.

A review of the provisions relating to the credit brought out the conclusion that the rules governing the eligibility of taxpayers for the credit required only one change. Congress decided to make it clear that joint owners of energy conservation property are eligible for the credit when the owners occupy different dwelling units but share the cost and use of the property. Congress believed that prior law did cover this situation but made a change in the statute simply to assure that this case was covered.

Explanation of Provisions

General provisions relating to residential energy credits

Joint ownership.—In cases of joint ownership of qualified property by 2 or more individuals with respect to 2 or more dwelling units used as principal residences by such individuals, each owner will be entitled to his share of the residential energy credit, and each will have the standard limit on the maximum amount of expenditures for energy conservation or renewable energy source property eligible for the credit.

Standards for secretarial determination.—The Secretary's discretionary authority in prior law has been supplemented with the establishment of standards that limit the exercise of the authority in evaluating whether items should be added to the list of qualified equipment. The Secretary must use three criteria in making a determination on the specification of an item as eligible for the energy conservation credit or of an energy source for which equipment is eligible for the renewable energy source credit. First, the Secretary cannot make such a specification unless he determines that it would result in a reduction in consumption of oil and natural gas and that this reduction would be sufficient to justify the resulting decrease in Federal revenues. Second, an item or a source cannot be specified unless the Secretary finds that such a specification would not result in an increased use of any item which is known to be, or reasonably suspected to be, environmentally hazardous or a threat to public health or safety. Third, such

a specification cannot be made unless the Secretary finds that available Federal subsidies do not make such specification unnecessary or inappropriate (in the light of the most advantageous allocation of economic resources).

In making a determination under the first criterion, the Secretary, after consultation with the Secretary of Energy, is required to estimate the amount by which the specification of the energy conservation item or the renewable energy source will cause a reduction in consumption of oil and natural gas. In making this estimate, the Secretary is required to take into account at least the following factors: (a) the extent to which the use of the property to be specified will be increased as a result of the specification, (b) whether sufficient capacity is available to increase production to meet increases in the demand for any products which might be caused by such specification, (c) the amount of oil or natural gas used directly or indirectly in the manufacture of the property and items necessary for its use, and (d) the estimated useful life of the item or other items necessary for its use. The Secretary will also take into account the extent additional use of the property leads, directly or indirectly, to the reduced use of oil or natural gas. Indirect use of oil or natural gas includes use of electricity derived from oil or natural gas.

In comparing the reduction of oil and natural gas consumption and the Federal revenue loss, the Secretary must also determine, after consultation with the Secretary of Energy, whether the specification of the property compares favorably, on the basis of the reduction in oil and natural gas consumption per dollar of cost (including revenue loss) to the Federal Government, with other Federal programs in existence or being proposed.

The Secretary is required to make a final determination with respect to any request by an applicant for specifying a conservation item or renewable energy source within one year after the filing of the request, together with any information required to be filed with the request. Each month the Secretary is required to publish a report of any request denied during the preceding month and the reasons for the denial.

In the case of any property which the Secretary specifies as eligible for the credit, the credits are allowed for expenditures made on or after the date on which final notice of the specification is published in the Federal Register. The Secretary may prescribe by regulations that such expenditures made before the close of the taxable year in which the date occurs shall be taken into account in the following taxable year.

Rules to prevent double benefits.—Under prior law, which is not amended by this Act, expenditures financed by Federal, State, or local grants which are exempt from Federal income tax were not eligible for a residential tax credit. In addition, the Act provides that the portion of the expenditures which is financed by subsidized energy financing is not to be eligible for a tax credit. Further, the expenditure limits on energy conservation and renewable energy source property for a particular dwelling are to be reduced by the portion of expenditures financed by subsidized energy financing, as well as by the amount of nontaxable Federal, State or local government grants used to purchase the energy conservation or renewable energy source property.

Subsidized energy financing means financing provided under a Federal, State or local government program, a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy. The term includes, but is not limited to, the direct or indirect use of tax-exempt bonds for providing funds under such a program. Subsidized energy financing, however, does not include loan guarantees.

Grants which are taxable are not taken into account under these rules because their taxation serves as a partial offset; similarly, credits against State and local income taxes are not taken into account because the deductibility of these taxes under the Federal income tax implies that the effect of these credits is equivalent to the effect of a taxable grant.

The reductions in the amount of qualified expenditures and in the expenditure limits will apply to taxable years which begin after December 31, 1980, with respect to financing or grants made after that date.

In addition, the Secretary is given the authority to require persons having control of a program which provides subsidized energy financing or an energy grant program to make a return containing the name and address of each individual receiving the financing or grant and the amount of financing or grant received under the program.

Renewable energy source equipment

The credit rate for renewable energy source property is increased to 40 percent of the first $10,000 of expenditures. Thus, the maximum credit available is $4,000 with respect to each residence owned by the taxpayer during the period of April 20, 1977, through December 31, 1985. The increase in the rate of the credit to 40 percent does not affect the $10,000 expenditure limit, which was retained. For example, if a taxpayer made qualifying expenditures of $4,000 in 1979 for which a credit of $1,000 was allowed, then the maximum further credit available for expenditures on that residence will be $2,400; that is, 40 percent of $6,000 of additional qualified expenditures.

In addition, the following additions are made to the equipment eligible for this credit:

(1) Equipment to produce electrical energy from solar or geothermal energy source property installed with respect to a residence;

(2) Expenditures for labor costs properly allocable to the onsite preparation, assembly or original installation of renewable energy source property eligible for the credit and expenditures for an onsite well drilled for any geothermal deposit, unless the deduction for intangible drilling costs has been claimed for any portion of these expenditures; and

(3) The cost of a solar roof panel installed as a roof (or a portion of a roof) even though a roof by itself is a structural component. (As under prior law, however, renewable energy source property shall not include other structural components of a residence even though they also may play an ancillary role related to renewable energy source property.)

Effective Date

The increased tax credit for renewable energy source property applies to expenditures made in taxable years that begin after December 31, 1979. The amendments made with respect to electrical energy from solar or geothermal sources, the credit for geothermal intangible drilling costs and solar roof panels apply to expenditures made after December 31, 1979, in taxable years ending after such date. The amendments limiting double benefits apply after December 31, 1980. The other amendments apply after December 31, 1979.

Revenue Effect

The reduction in budget receipts is expected to be $6 million in fiscal year 1980, $42 million in 1981, $52 million in 1982, $67 million in 1983, $88 million in 1984, and $128 million in 1985.

C. BUSINESS TAX INCENTIVES

1. Business Energy Investment Credits (Secs. 221–223 of the Act and secs. 46, 48 and 167 of the Code)

Prior Law

A 10-percent energy investment credit is available for investments in certain business energy property. The amount of the credit generally was 10 percent of a taxpayer's cost of acquiring or constructing eligible property. The rate of the energy credit is reduced to 5 percent where an item of energy property is financed to any extent with the proceeds of an industrial development bond, the interest on which is exempt from Federal income tax.

To be eligible for an energy credit, property must be depreciable with a useful life of three years or more. In addition, property must be new (not used) property which was first placed in service after September 30, 1978.

Qualifying energy property generally includes equipment which utilizes certain energy resources other than oil or natural gas or a product of oil or natural gas. Specifically, energy property includes boilers, burners, and related fuel handling and pollution control equipment to burn substances (such as coal, wood, agricultural and municipal waste, and biomass) other than oil or natural gas (or their products) or to convert these alternate substances into a synthetic fuel. Equipment which uses coal as a feedstock for the manufacture of chemicals or other products (other than coke or coke gas) and equipment that modifies existing equipment to use an alternate substance as at least 25 percent of a fuel or feedstock also is eligible for the energy credit. In addition, energy property includes equipment to produce, distribute or use geothermal energy, equipment which uses solar or wind energy to generate electricity or to heat or cool a structure, equipment to produce natural gas from geopressured brine or oil from shale, and equipment to recycle solid waste.

The energy investment credit is also provided for a category of "specially defined energy property", which consists of specific kinds of equipment used to reduce loss of heat or energy and to improve the energy efficiency of commercial and industrial facilities and processes in existence on October 1, 1978. In addition to specific items of equipment listed in the Code, the Secretary of the Treasury is authorized to specify other similar items of energy conservation property under regulations as being eligible for the credit.

The energy credit is available for structural components of a building which otherwise qualify as energy property. Except for oil shale equipment and geopressured gas equipment, property used to provide electrical, gas, steam and other public utiilty services is not eligible for the credit.

The energy credit applies against all tax liability not offset by other tax credits. Excess energy credits from a taxable year may be applied, like regular investment credits, against tax liability for the three preceding and seven succeeding taxable years. Energy credits for solar or wind energy property that exceeded tax liability were fully refundable.

The energy credits generally apply to qualifying costs incurred for the period from October 1, 1978, through December 31, 1982.

Reasons for Change

Congress reviewed the energy investment tax credit to determine whether changes were desirable in view of experience with the provisions, their effectiveness in helping to realize the energy policy objectives of the Energy Tax Act of 1978, and the increasing urgency for finding and developing a broader and more abundant range of energy sources and for conserving energy.

The experience with the business credits enacted by the Energy Tax Act of 1978 indicated that the incentives did not apply to a sufficiently broad range of alternative energy sources, equipment, methods to produce them, and means to conserve use of oil- and gas-derived energy. Several forms of energy property which use alternative energy resources were not included in the 1978 legislation, and Congress decided that energy-related investment incentives had to be expanded in order to accelerate conversion to these resources.

Congress was also concerned that the overlapping of these investment credits and other government subsidy programs could result in an inefficient use of private and public resources. The compound effect of various subsidized loan and grant programs could lead to a situation in which the taxpayer could purchase subsidized equipment with very little expenditure of his own funds; and this could encourage inefficiency by diverting substantial resources from more effective uses. Thus the Act contains rules which, in conjunction with the prior treatment of nontaxable grants, require, in effect, that the purchaser of eligible equipment choose between the tax credit, on the one hand, and subsidized energy loans and nontaxable grants, on the other hand.

Many industrial investments, especially those which involve construction of new facilities or development of production facilities for new technologies, require longer periods to design and construct. New energy technologies, particularly, involve more than usual amounts of uncertainty about the probable success of the entire project as well as whether any components of a new process will require redesign. These considerations have caused Congress to extend the termination date of the energy credit for certain projects with long construction periods where affirmative commitments have been made before the general expiration date and to increase the credit and extend the effective period for certain other categories of energy equipment.

Explanation of Provisions

Solar or wind property

Under the Act, the energy credit for equipment which uses solar or wind energy to generate electricity or to provide heating, cooling

or hot water in a structure is increased from the 10-percent credit under prior law to a 15-percent credit, and the termination date of the credit for this property is extended from December 31, 1982, through December 31, 1985. In addition, equipment which uses solar energy to provide process heat is added as eligible solar energy property. Solar process heat equipment includes, for example, collectors and heat exchangers which use solar energy to generate steam at high temperatures for use in such facilities as beverage bottling plants, laundries and canneries. These provisions are effective for qualifying investments after December 31, 1979.

The Act also repeals the refundable feature of the solar and wind energy credits, effective for taxable years which begin after December 31, 1979. Solar or wind energy credits attributable to qualified investment on or after the January 1, 1980, effective date of this provision will not be refundable even if they are carried back to taxable years which begin before January 1, 1980.

Geothermal equipment

The 10-percent nonrefundable energy credit under prior law for equipment to produce, distribute or use geothermal energy (including equipment for the generation of electricity up to, but not including, the electrical transmission stage) is increased to a 15-percent credit under the Act, effective for qualifying investments after December 31, 1979. In addition, the termination date for this credit is extended from December 31, 1982, to December 31, 1985.

Ocean thermal equipment

A new category of energy property, ocean thermal equipment, is provided a nonrefundable energy credit of 15 percent for certain investments in qualifying equipment during the period from January 1, 1980, through December 31, 1985. The credit is allowed for investments in qualifying equipment only at two locations which will be designated by the Secretary of the Treasury after consultation with the Secretary of Energy.

Ocean thermal equipment is defined as equipment which converts ocean thermal energy into electrical energy or another form of useful energy. Qualifying equipment in this category of energy property includes turbines, generators and related equipment (such as pumps, piping and heat exchangers) up to, but not including, the transmission stage (i.e., transformers and transmission lines, etc., are excluded). Qualifying ocean thermal energy equipment also includes specially designed vessels and structures used to support, house and service this equipment.

The Act also makes a technical amendment to prior law to provide an exception from the investment credit rule of general application which requires that qualifying property be used predominantly within the United States. Under this technical amendment, the generally applicable United States use limitation will not apply to qualifying ocean thermal equipment which is owned by a United States person (as defined in Code sec. 7701(a)(30)) and which is used in international or territorial waters to generate energy for use in the United States. (The term United States is defined in Code sec. 7701 (a)(9) to include only the 50 States and the District of Columbia.)

Small-scale hydroelectric generating property

The Act provides an 11-percent business energy credit for a limited period of time for investments in qualifying hydroelectric generating property.

Public utility property is eligible for this credit if the investment credit's normalization requirements for public utility property under Code sec. 46(f) are satisfied. The Act also allows the regular investment credit for fish passageways which qualify as hydroelectric energy property, effective for qualifying investments after December 31, 1979.[1] Qualified hydroelectric generating property means (1) equipment for generating electric energy from water (up to, but not including, the electrical transmission stage) at a qualified hydroelectric site, and (2) structures for housing such equipment, fish passageways, and dam rehabilitation property, required by reason of the installation of electrical generation equipment (described in (1)) at the qualified hydroelectric site.

Qualified hydroelectric site.—A qualified hydroelectric site, in general, means any site which has an installed capacity of less than 125 megawatts (1) at which there is a dam (including certain Government-owned dams) the construction of which was completed prior to October 18, 1979, and which is not significantly enlarged after such date or (2) at which electricity is to be generated without any dam or other impoundment of water. For this purpose, the term "installed capacity" means, with respect to any site, the installed capacity of all electrical generating equipment placed in service at the site (regardless of whether any of that equipment was qualified hydroelectric generating property). The term also includes the capacity of equipment installed at the site during the three taxable years following the taxable year in which the equipment in question is placed in service. As a result, the credit will be recaptured to the extent that the installed capacity limits (described below) are exceeded within that time period. A qualified hydroelectric site includes only sites which are located on a natural water course or constructed water flow and which generate electric energy from the flow or fall of water. The provision does not apply to pumped storage facilities, ocean thermal facilities, or ocean tidal facilities.

Existing dam sites.—Existing dam sites generally include any at which electricity is, or has been, generated, as well as locations of existing dams which have not been used in connection with electricity generation. In addition, a dam site or other impoundment site includes any water passageways that are fed from the water behind the dam or other impoundment, if the primary purpose of the water passageways is for the generation of electricity.

A dam, the construction of which was completed before October 18, 1979, means any dam or barrier for the impoundment of water, built across a natural or manmade watercourse, which was completed before October 18, 1979, and which does not require any significant construction or enlargement of the impoundment structure (other than repairs or reconstruction) in connection with the installation of the hydro-

[1] Congress did not intend to create an inference by this legislation concerning whether the regular investment credit was properly allowable for fish passageways under prior law.

electric power project. For purposes of the Act, the construction of penstocks, powerhouses, fish passageways and similar structures does not constitute significant construction or enlargement of the impoundment structure. In addition, the reconstruction or repair of dam structures which increases the water level or impoundment of a dam to its original or designed levels will not constitute significant construction or enlargement of the impoundment structure if the reconstruction or repairs were undertaken in order to strengthen a dam or to eliminate leakage. On the other hand, construction which extends a dam or increases the height of a dam for purposes of increasing the water level impoundment beyond its original designed levels will constitute significant construction or enlargement of the impoundment structure.

Non-dam sites.—A site at which electricity is to be generated without dam or other impoundment of water includes conduit sites (such as flood control, sewage treatment flows, irrigation water flows, and other similar constructed water flows) and natural water flows (such as rivers and streams). In the case of a conduit site, the construction of the site may be completed either before or after October 18, 1979. For purposes of this provision, the generation of electricity at the site of a gate or other water control structure in an irrigation ditch or canal is not treated as generation at the site of a dam or water impoundment.

Qualified hydroelectric generating property.—In addition to being located at a qualified hydroelectric site, property qualifying for the investment credit must also be either (1) equipment to increase capacity for generating electric energy from water or (2) structures for housing such equipment, fish passageways, or dam rehabilitation property, required by reason of the installation of electrical generation equipment.

Qualified hydroelectric generating property includes generating equipment such as turbines and generators. It also includes the capital costs for repairing or restoring existing nonfunctional generating equipment. However, such equipment only includes equipment up to (but not including) the transmission stage.

In addition, qualified hydroelectric generating property includes structures (such as powerhouses and similar structures) for housing generating equipment, fish passageways (and related equipment such as fish counters), and dam rehabilitation property, but only if such equipment is required by reason of the installation of generating equipment. The term "dam rehabilitation property" includes property for the reconstruction of the dam structure and related structural elements which have been left in place. It includes the cost of reconstruction or rehabilitation of a dam which impounds water for use by the generating equipment, such as the cost of strengthening the dam and eliminating leakage. However, it does not include the cost of extending or increasing the height of the dam for purposes of increasing the water level or the size of the impoundment. In the case of an impoundment which does not meet state or Federal spillway capacity or other requirements, the term "dam rehabilitation property" includes the replacement of the entire impoundment structure. Also, in the case of non-dam sites, qualified hydroelectric generating property does not include the cost of the structures which create or contain the water

concourse or flow but does include the cost of necessary alterations to a gate or other water control structure to facilitate installation of generating equipment.

Installed capacity fraction.—Under the Act, the entire cost of the qualified hydroelectric generating property is eligible for the energy credit where the installed capacity of the qualified hydroelectric site does not exceed 25 megawatts. The energy credit is phased out as the total capacity of all electric generating equipment installed at the site increases from 25 megawatts to 125 megawatts. For these purposes, increases is generating capacity attributable to qualifying costs for restoring existing nonfunctional equipment, and increases which occur during the three taxable years following the year in question, are taken into account. Between 25 to 100 megawatts, qualified investment is reduced proportionately; and between 100 to 125 megawatts, the energy credit is phased out entirely. Specifically, the portion of the total cost eligible for the energy credit is the cost of the qualified hydroelectric generating property multiplied by a fraction, the numerator of which is 25 reduced by 1 for each whole megawatt by which the installed capacity exceeds 100 megawatts, and the denominator of which is the number of megawatts of installed capacity (but not in excess of 100). For example, assume that in each of the years 1975, 1980 and 1983, the taxpayer installs at an existing dam, electric generating equipment with an installed capacity of 25 megawatts. Thus, at the end of 1983, the total installed capacity would be 75 megawatts. For each of the years 1980 and 1983, the 11-percent credit would be computed on the basis of 25/75ths of qualified investment.

Miscellaneous.—The Act does not include provisions concerning depreciation treatment of small-scale hydroelectric generating property. However, Congress understands that rates for the sale of electricity produced by hydroelectric facilities owned by taxpayers other than electric utilities generally are not regulated on a rate of return basis, and it is intended that this qualifying hydroelectric generating property consequently will not be classified generally as public utility property which is subject to the Code section 167(l) limitations on the use of accelerated methods of depreciation.

Effective date.—This credit is generally available for the period from January 1, 1980, through December 31, 1985. In addition, the effective period is extended for three additional years, through December 31, 1988, for qualifying investments which arise from a hydroelectric project for which an application was docketed by the Federal Energy Regulatory Commission before January 1, 1986.

Cogeneration equipment

The Act provides a 10-percent energy credit for a new category of energy property, cogeneration equipment. This category consists of property which is an integral part of a system for using the same fuel to produce both "qualified energy" and electricity at an industrial or commercial facility at which electricity or qualified energy was produced on January 1, 1980. For this purpose, the term "qualified energy" means only steam, heat, or other forms of useful non-electric energy for industrial, commercial, or space-heating purposes (other than electricity production). As a result, cogeneration equipment

generally will consist of equipment to enable a boiler, burner, or other energy-using system at an existing facility to produce steam, heat or other useful energy and also to produce electricity. To qualify, the equipment must result in an increase in the facility's cogenerating capacity, including the start of cogenerating activity. This credit is available for qualifying investments during the period from January 1, 1980, through December 31, 1982.

The credit is allowed under the Act only where qualifying equipment is installed (1) in an industrial or commercial facility which produced steam or generated electricity as of January 1, 1980, and (2) as part of an energy-using system which does not use oil, natural gas, or a product of oil or natural gas, as a fuel or where these fuels are used only for startup, backup or flame stabilization purposes and comprise not more than 20 percent of the fuel consumed by the system, determined on the basis of Btu's consumed each year. For this purpose, agricultural and water purification and desalinization facilities are considered to be industrial facilities. The determination of whether cogeneration equipment qualifies will be made for each separate energy using system in a facility. Cogeneration equipment includes qualifying equipment added to an energy using system to begin either cogenerating activity or expand existing cogenerating capacity and also includes costs of rehabilitating existing cogeneration equipment in circumstances where the addition of new cogeneration equipment would qualify for the credit. Where existing cogenerating equipment is replaced, the credit is available for the replacement cogeneration equipment to the extent attributable to incremental cogenerating capacity. As under existing law, if the property ceases to be qualifying energy property, recapture of the energy credit may occur.

For purposes of determining eligibility for the credit where there has been an increase in the capacity of the system to cogenerate, equipment would not be eligible if it merely increases the capacity of the system to produce the primary energy product of the system. For example, if an energy-using system is presently producing steam for industrial or commercial process use as its primary energy product and electricity as its secondary energy product, equipment that merely increases the system's steam capacity would not qualify because only the primary energy product would have been increased. However, the boiler may otherwise be eligible for an energy credit as alternative energy property if it primarily uses an alternate fuel, including fuel derived from biomass.

Congress intends that the determination of primary and secondary energy products within an energy using system will be made on the basis of the relative amounts of energy produced or generated by these two functions. In the case of an energy using system where the primary energy product is steam, heat or other useful energy (such as shaft power) for process or space heating purposes, qualifying cogeneration equipment includes a turbine and generator to produce electricity, and also any other equipment up to (but not including) the electrical transmission stage. Where electricity is the primary product, qualifying equipment includes that necessary to recover and distribute, but not to use, excess energy after the electrical generation function.

Specially defined energy property

The Act adds energy-saving modifications to alumina electrolytic cells to the items on the list of specially defined energy property eligible for a 10-percent energy credit for the period from October 1, 1978, through December 31, 1982. Qualifying modifications to alumina cells are intended to mean either a substitution or a substantial change in technology and not periodic cleaning, repairs, or replacement of these cells or their components. For example, qualifying modifications include energy saving additions to, or substitutions of, components of the electrolytic reduction cell or pot, such as changes to anode or cathode configurations and the addition of thermal insulation.

The Act also provides standards for the exercise of the authority delegated under present law to the Secretary of the Treasury to specify additional items of qualifying specially defined energy property. The standards provided by the Act for purposes of the business energy credit are the same standards as those enacted for purposes of identifying additional items of energy conservation property or renewable energy sources eligible for a residential energy credit under Code section 44C.

Petroleum coke and petroleum pitch

The Act provides an exception to the provisions in prior law which generally deny the regular investment credit and accelerated methods of depreciation to certain boilers which use oil, natural gas or their products as a primary fuel. Under the Act, an exception from these denial provisions is created for petroleum coke and petroleum pitch so that the regular investment credit and accelerated methods of depreciation will be allowed for boilers which use these bottom-of-the-barrel byproducts of petroleum refining as a primary fuel.

Coal feedstock equipment

The Act modifies provisions in prior law concerning equipment which uses coal to produce certain feedstocks. Under these changes, where coal (including lignite) is used to produce a feedstock for the manufacture of chemicals and other products, qualifying equipment will generally qualify only to the point where either a marketable substance or a substitute for a feedstock derived from petroleum or natural gas is produced. A marketable substance is one that is regularly offered for commercial sale. However, the production of small (either in quantity or value) amounts of marketable byproducts incident to the manufacture of the primary product will not render the equipment ineligible.

The Act also provides that qualifying equipment to produce a feedstock from coal (including lignite) includes equipment to treat intermediate products derived from this coal. Examples of such equipment include equipment to upgrade a coal-derived low-Btu gas to a medium or high Btu gas, to produce methanol or ammonia for use as a feedstock from coal-derived gases or liquids, and to produce hydroprocessed liquids or solids from coal for use as feedstocks in the production of chemicals and other products. Equipment to convert coal into feedstocks for the manufacture of chemicals or other products

does not include equipment, such as an oxygen plant, which is not directly involved in the treatment of coal or a coal product, but produces a substance which is, like coal, a basic feedstock or catalyst used in a coal conversion process. Also, qualifying equipment in an integrated process will not be ineligible merely because parts of the process are owned by different taxpayers.

Coke and coke gas equipment

The Act provides a 10-percent energy investment credit, under the category of alternative energy property, for new coke ovens and for costs incurred in the reconstruction or rehabilitation of existing coke ovens to produce coke and coke gas for use as a fuel or feedstock. Qualifying equipment also includes required pollution control equipment and related on-site equipment to handle, store and prepare coal for use in coke ovens. This provision is effective for qualifying investments during the period from January 1, 1980 through December 31, 1982.

Biomass property

The Act makes several changes to prior law for equipment used in connection with the production or consumption of certain biomass fuels. Under the Act, the 10-percent energy credit for alternative energy property, which terminates after December 31, 1982, generally is extended for three additional years, through December 31, 1985, for qualifying property that is used to convert biomass into a synthetic solid fuel, or to burn this synthetic fuel or biomass. Qualified investment for equipment that converts biomass to alcohol for fuel purposes is also eligible for the 10-percent energy investment credit through December 31, 1985, but only if the equipment producing the alcohol uses a primary energy source (i.e. more than 50-percent of the full energy requirement for the taxable year) other than oil, natural gas, or a product of oil or natural gas.

In addition, the Act extends the 10-percent energy credit to equipment that stores fuel derived from garbage (i.e., refuse-derived fuel) at the site where the fuel is produced. This equipment, which was not eligible for the energy credit under prior law, is eligible for the 10-percent energy credit from January 1, 1980, through December 31, 1985.

Under these provisions, biomass is generally any organic substance other than oil, natural gas, or coal, or a product of oil or natural gas or coal. For this purpose, biomass includes waste, sewage, sludge, grain, wood, oceanic and terrestrial crops and crop residues and includes waste products which have a market value. Congress also intends that the definition of biomass does not exclude waste materials, such as municipal and industrial waste, which include processed products of oil, natural gas or coal, such as used plastic containers and asphalt shingles.

Biomass fuel or feedstock handling, storage, and preparation equipment and pollution control equipment as defined under Code secs. 48(l)(3)(A)(vi) and(vii) are also eligible for the 10-percent energy credit through 1985 under the Act.

Extension of the credit period for alcohol fuel equipment applies where the primary source of energy is an energy resource (such as

coal or geothermal or solar energy) other than oil or natural gas substances. In addition, property that uses an oil or natural gas substance as its primary energy source and that is constructed by the taxpayer and placed in service after 1982 is allowed the energy credit under the rules of Code secs. 46(a)(2)(C)(i)(I) and 48(m) only to the extent of costs attributable to construction before 1983. Such property acquired by the taxpayer and placed in service after 1982 is not allowed an energy credit under Code secs. 46(a)(2)(C)(i)(I) or 46(a)(2)(C)(i)(VI). As under existing law, if the property ceases to be qualifying energy property, recapture of the energy credit may occur.

Intercity buses

The Act provides a 10-percent energy investment credit for certain intercity buses of a common carrier which is engaged in providing passenger or charter intercity bus transportation and is regulated by the Interstate Commerce Commission or a similar State regulatory authority. The credit applies to qualifying intercity buses to the extent a taxpayer's fleet seating capacity is increased over that for the preceding year.

The determination of incremental fleet size is made by comparing the operator's fleet size at the end of the taxable year during which qualifying buses were placed in service with the operator's fleet size at the end of the immediately preceding taxable year. In making this determination, there will be taken into consideration the total operating seating capacity, including buses either owned by or leased to the taxpayer-operator and those of a related taxpayer-operator [2] of intercity buses used on a full-time basis during these two periods. For purposes of defining full-time use, it is intended that this definition include qualifying intercity buses acquired at the end of the taxable year and used on a full-time basis for the remainder of the year (or, if acquired on the last day of the year, will be used on a full-time basis), even if these buses are not operated for any specified number of miles during the year they are acquired.

Qualifying intercity buses are defined as automobile buses owned and operated by the taxpayer, the chassis and body of which are exempt (under Code sec. 4063(a)(6)) from the 10-percent excise tax generally imposed under Code section 4061(a) on trucks and buses. In order to distinguish intercity buses from local transit buses for purposes of this provision, qualified buses must also have seating capacity for at least 35 passengers (in addition to the driver) and one or more baggage compartments, separate from the passenger area, with a capacity of at least 200 cubic feet.

The energy credit for intercity buses applies to qualifying buses acquired and placed in service by the operator after December 31, 1979, and before January 1, 1986.

Affirmative commitments

The Act extends the expiration date through December 31, 1990, for energy credits which otherwise expire after December 31, 1982, if certain conditions are satisfied. Under these provisions, the effective

[2] It is expected that rules similar to those contained in Code section 52(a) and (b) will apply for purposes of defining related taxpayers.

date for energy credits on energy property constructed or installed in connection with long-term projects with a normal construction period of two years or more (as this term is defined under Code section 46(d)(2), relating to qualified progress expenditures) is extended through 1990, if (1) before January 1, 1983, all engineering studies necessary for commencement of construction of the project have been completed by or for the taxpayer and the taxpayer has also, by January 1, 1983, applied for all environmental and construction permits required under Federal, State or local law in connection with commencement of construction of the project; and (2) the taxpayer, before January 1, 1986, has entered into binding contracts to acquire or construct at least 50 percent of the total estimated value of all equipment which is specially designed to become part of this project. It is expected that this provision will cover such energy property as large boiler systems, coal gasification and liquefaction projects and coke ovens, for which the normal construction period is two years or more.

Double-dipping rules

The Act provides rules which do not allow an energy tax credit on the proportionate cost of energy property that has been acquired with the proceeds from subsidized energy loans or industrial development bonds. Grants which are included in taxable income are not taken into account under these rules because their taxation serves as a partial offset. Similarly, credits against State and local income taxes are not taken into account because the deductibility of these taxes under the Federal income tax implies that the effect of these credits is equivalent to the effect of a taxable grant.

Under prior law if property is financed with nontaxable government grants, the tax basis in the property, for such purposes as depreciation and investment credits (including energy investment credits), is reduced to the extent that the property is financed with such grants. These rules, which partially offset the benefit of these grants, are not changed under the Act. The Act provides a similar rule, with respect to energy credits, to the extent that property is financed with tax-exempt industrial development bonds or certain other governmental subsidized financing.

When qualified investment is financed in whole or in part by the proceeds of tax-exempt industrial development bonds or by subsidized energy financing, the amount taken into account for purposes of applying the energy tax credit percentage is qualified investment multiplied by a fraction which is determined by dividing that portion of qualified investment in the property which is allocable to subsidized financing, loans or grants by qualified investment in the property and subtracting this quotient from one.

Subsidized energy financing means financing provided under a Federal, State, or local program, a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy. Subsidized financing includes, but is not limited to, the direct or indirect use of tax-exempt bonds for providing funds under such a program. Subsidized financing does not include, however, loan guarantees.

Under provisions enacted in 1978, one-half of the energy tax credit percentage is allowed for property financed in whole or in part by in-

dustrial development bonds. Under this rule, when energy property is installed in conjunction with other property that is financed by industrial development bonds because such other property is described in section 103(b)(4), the energy property is not considered to be financed in whole or in part by industrial development bonds. The rule provided in the Act replaces the current law rule and will generally be effective for periods after December 31, 1982. However, in the case of property which is allowed the energy tax credit percentage for the first time under the Act, this rule would apply to periods after December 31, 1979. This additional property includes qualified hydroelectric generating property, cogeneration equipment, certain intercity buses, ocean thermal property, certain property which produces coke or coke gas or uses coal to produce certain chemicals, property which generates process heat from solar energy, alumina electrolytic cells, and storage equipment for fuel derived from garbage. In the case of property financed by subsidized energy financing other than financing provided from the proceeds of any tax-exempt industrial development bond, no financing made before January 1, 1980, will be taken into account.

Effective dates

These provisions generally are effective for property placed in service after December 31, 1979, to the extent of expenditures incurred after that date. The provision which relates to the qualification of modifications to alumina electrolytic cells will be retroactive to apply to expenditures incurred after September 30, 1978, for qualifying modifications placed in service after that date. The double dipping rules are generally effective after December 31, 1982, except in the case of new items of energy property added by the Act, for which the effective date is December 31, 1979.

Revenue effect

The revenue loss from the changes in the business energy investment credit is expected to be $41 million in fiscal year 1980, $160 million in 1981, $201 million in 1982, $488 million in 1983, $932 million in 1984, and $1,199 million in 1985.

2. Alternative Fuel Production Credit (Sec. 231 of the Act and new sec. 44D of the Code)

Prior Law

Prior law contained no income tax credit for the production and sale of fuel derived from energy sources other than oil and conventional sources of natural gas.

Reasons for Change

Congress believed that the use of fuels derived from energy sources other than oil and conventional natural gas should be encouraged by providing a tax incentive for their production and sale. Because these alternative fuels frequently compete with oil and gas, Congress believed that production incentives should be linked to the uncontrolled price of domestic oil and should phase out as that price rises to the level where efficiently produced alternative fuels should be able to compete effectively with oil. Evidence presented to the tax writing committees indicated that the appropriate phaseout range is when the uncontrolled price of domestic oil is between $23.50 and $29.50 in 1979 prices, and Congress set this range for the phaseout of the production credit. Congress was aware that the price of oil exceeded $29.50 at the time of enactment and intended that the credit generally act only as protection for producers of alternative fuels against oil price reductions, in effect a guaranteed price floor. However, special rules were provided, for a limited time only, for production of qualifying processed wood fuel, steam from solid agricultural byproducts, and gas from Devonian shale, to allow a production credit when the price of oil is above $29.50.

Explanation of Provision

Overview

The Act provides a tax credit for the domestic production and sale of qualified fuels to unrelated persons. Such fuels generally must be produced and sold after December 31, 1979, and before January 1, 2001, from (a) facilities placed in service after December 31, 1979, and before January 1, 1990, or (b) wells drilled after December 31, 1979, and before January 1, 1990, on properties which first began production after December 31, 1979.[1]

The credit equals $3 for each 5.8 million Btu's of energy. (One barrel of crude oil contains approximately 5.8 million Btu's.) All Btu measurements must be made without regard to any Btu's attributable to materials or energy sources other than the qualified fuel. Except for

[1] A technical correction is needed to new Code sections 44D(f)(1)(B) and 44D(f)(2)(A)(i) to change the number "3" to "31."

gas produced from a tight formation, the $3 amount is indexed for post-1979 increases in the GNP deflator.

The credit phases out as the annual average wellhead price of uncontrolled domestic oil rises from $23.50 to $29.50 a barrel. The phaseout range is adjusted for post-1979 changes in the GNP deflator.

Qualified fuels

The credit is available for production and sale of the following fuels:

(1) Oil produced from shale and tar sands;

(2) Gas produced from geopressured brine, Devonian shale, coal seams, or a tight formation;

(3) Gas produced from biomass;

(4) Liquid, gaseous, or solid synthetic fuel (including alcohol) produced from coal (including lignite), including such fuels when used as feedstocks;

(5) Qualifying processed wood fuels; and

(6) Steam from solid agricultural byproducts (not including timber byproducts).

For purposes of the credit, the definition of natural gas from geopressured brine, Devonian shale, coal seams, or a tight formation is that determined by the Federal Energy Regulatory Commission in accordance with section 503 of the Natural Gas Policy Act of 1978 (NGPA). However, in the case of natural gas produced from a tight formation, the credit applies only to gas which is price-controlled and which is entitled to at least 150 percent of the then applicable gas ceiling price established under section 103 of the NGPA. In addition, the credit is inapplicable to any gas production from any property on which a well is located which is subject to an election to receive an incentive price under section 107(d) of the NGPA. Similarly, the credit is inapplicable to any gas production from a property which produced such gas in marketable quantities before January 1, 1980.

Liquid, gaseous, or solid synthetic fuels produced from coal or lignite include solvent refined coal. In addition, alcohol fuels produced from coal are included in the definition of qualified fuels. Unlike the situation applicable to other qualified fuels, fuels produced from coal may be used as feedstocks without making their production ineligible for the credit.

Qualifying processed wood fuel is any processed solid wood fuel which has a Btu content per unit of volume or weight, determined without regard to any nonwood elements, which is at least 40 percent greater per unit of volume or weight than the Btu content of the wood from which it is produced. The latter Btu measurement must be made immediately before the wood is processed, and both pre- and post-processing measurements must be made without regard to any Btu content attributable to non-wood elements, e.g., oil, gas, wax, plastic, glue, etc. (Under the general credit rule, Btus attributable to such additives are disregarded in determining the amount of the credit for the year.)

To come within the definition of qualifying processed wood fuel, the solid wood fuel produced must have been subjected to a treatment process. In no event, however, does qualifying processed wood fuel include charcoal, fireplace products, or products used for ornamental

or recreational purposes, e.g., barbecue fuel or garden ground coverings. This exclusion encompasses fireplace products marketed in the form of "convenience logs," and similar residential compressed products which are wood based.

Qualifying processed wood fuel must be derived from wood and wood products. Thus, it must be derived from timber, trees, forestry and timber wastes and residues, or wood based industrial waste. It does not include products made from municipal and other waste (such as paper), or from agricultural items.

The taxpayer may elect, in accordance with regulations, to have the Btu content per unit determined on a volume or weight basis, and must establish that production satisfies the 40-percent enhancement criterion. The election applies to all production from a facility and for all taxable years beginning with the year with respect to which it is made. Once made, the election may be revoked only with the consent of the Secretary.

The term "solid agricultural byproducts" includes only solid byproducts of agriculture or farming. It does not include timber byproducts or biomass generally. For purposes of the credit, qualified fuels include steam only when it is produced from solid agricultural byproducts. Such steam which is used by the taxpayer in his or her trade or business is treated as having been sold to an unrelated person on the date on which it is used.

Qualified fuels also include gas (as distinguished from steam) produced from biomass. The term biomass means any organic material which is an alternate substance, as defined for business energy tax credit purposes under section 48(l)(3)(B), other than coal, lignite, or a product of coal or lignite. Therefore, qualified fuels include gas produced from wood and agricultural byproducts.

Credit phaseout

The credit phases out proportionately as the annual average wellhead price for a barrel of uncontrolled domestic oil (the "reference price") rises from $23.50 to $29.50, adjusted for inflation. The reference price is to be estimated by the Secretary and published, together with the inflation adjustment factor, by April of the year following that for which the credit is being computed. For any year, the inflation adjustment is the ratio of the GNP deflator for the year (using the first revision published by the Department of Commerce) to the GNP deflator for 1979 (again using the first revision). The credit, or some part of the full $3 amount, is to be available for any year for which the reference price is within the phaseout range, as adjusted for inflation, even though the reference price may have exceeded that range for a prior year.

Credit offsets

The Act contains two "credit offsets" intended to limit the credit when the taxpayer uses other subsidies or tax benefits. First, to the extent that the credit would otherwise be available for the production and sale of any of the eligible fuels, it is reduced in proportion to Federal, State, and local grants, subsidized energy financing, and tax-exempt financing provided in connection with the construction or acquisition of the facility or its equipment. For this purpose, all tax-

exempt financing, all Federal, State, and local grants (whether or not taxable or energy related), and subsidized energy financing are taken into acount. Loan guarantees are not taken into account. The proportion of a facility deemed to be financed by these items equals the sum of the grants, subsidized energy financing and tax-exempt financing divided by the sum of the gross additions to capital account attributable to the project.

Second, the production credit is reduced, dollar-for-dollar, for energy investment credits allowed in respect of the property used to produce the qualified fuels eligible for the credit. All energy investment credits allowed to any party (including parties to a lease of the property and to predecessors) with respect to the fuel production property are taken into account.

This offset for energy investment credits applies only up to the point at which the full energy investment credit has been recaptured, either under the generally applicable provisions of section 47 (relating to certain dispositions) or under the special recapture rules of the production credit. (The Act, however, also provides that the amount of energy investment credit recaptured under section 47 must be reduced appropriately to take into account any reduction of the production credit attributable to a previous recapture of the energy investment credit under section 44D).

It is anticipated that the production credit will be taken into account by any Federal instrumentality in conjunction with decisions relating to loan guarantees, price supports, purchase agreements, and other subsidies.

Special rules

The previously described general rules apply to all qualified fuel production, regardless of the fuel's source. In addition, the following special rules apply to production of Devonian shale gas, qualifying processed wood fuel, and steam from solid agricultural byproducts:

Devonian shale gas.—For production and sales in calendar years 1980, 1981, and 1982, the phaseout of the credit for gas produced from Devonian shale is based on the price of deregulated natural gas, not deregulated oil. For sales during these years, the credit phases out as the average price of high cost natural gas (as determined under section 107(c)(2), (c)(3), and (c)(4) of the NGPA) rises from $4.05 to $5.08 per thousand cubic feet (mcf). For sales after 1982, the generally applicable credit phaseout based on the price of oil applies.

Qualifying processed wood.—The credit for qualifying processed wood is available only as to production and sales from facilities first placed in service in calendar years 1980 and 1981. As to production from those facilities, it is available for production and sales before either October 1, 1983, or three years from the date that the facility first is placed in service, whichever comes later. In addition, the phaseout based on the price of oil does not apply to production and sales during the first three years after the date the facility first was placed in service.

Steam from solid agricultural byproducts.—The credit for steam from solid agricultural byproducts is available only for production and use before January 1, 1985, in facilities placed in service after December 31, 1979. However, the phaseout based on the price of oil does

not apply to production and use of such steam during the first three years after the date that the facility first is placed in service. In addition, a special rule applies to post-1979 increases in the production capacity of facilities first placed in service before 1980. Under this rule, increases in a pre-1980 facility's capacity to produce steam from solid agricultural byproducts due to placing additional or replacement equipment in service after 1979 basically are treated as being attributable to facilities first placed in service after 1979. Therefore, production of steam attributable to these increases is eligible for the credit.

Effective Date

The credit applies to taxable years ending after December 31, 1979.

Revenue Effect

The revenue loss is expected to be $4 million in fiscal year 1980, $26 million in 1981, $54 million in 1982, $50 million in 1983, $18 million in 1984, and $8 million 1985.

3. Alcohol Fuels Provisions

a. Excise Tax Exemption for Gasohol and Other Alcohol Fuels (Secs. 232(a) and (b)(3)(A) of the Act and secs. 4041 and 4081 of the Code)

Prior Law

A manufacturers excise tax of 4 cents a gallon is imposed on gasoline sold by the producer or importer (sec. 4081). Also, a retailers excise tax of 4 cents a gallon is imposed on diesel fuel sold for use (or used) in a highwhay vehicle and on other special motor fuels sold for use (or used) in a motor vehicle or motorboat (sec. 4041).[1] The rates of these taxes are scheduled to be reduced to 1½ cents per gallon as of October 1, 1984.

A number of exemptions from these taxes are provided for certain uses of fuel (such as use in farming) as well as for certain tax-exempt users (such as State and local governments). In many situations, if tax-paid fuel is used for a tax-exempt use or by a tax-exempt user, a refund or credit may be obtained.[2]

Revenues from these taxes, as well as certain other excise taxes [3] imposed on highway-related items, are deposited in the Highway Trust Fund. Also, the Highway Trust Fund generally is reduced by credits or refunds of these taxes. Revenues from these taxes attributable to periods after September 30, 1984, are not to be deposited in the Highway Trust Fund.

Prior to the Energy Tax Act of 1978 ("the Energy Tax Act"), motor fuel which was a blend of gasoline and alcohol ordinarily would have been subject to a 4-cent-per-gallon tax if used in a highway vehicle. This is the same rate of tax as would apply to ordinary gasoline used in highway vehicles. Under the Energy Tax Act, gasohol (i.e., fuel which is a blend of gasoline, or other motor fuel, and alcohol) that is at least 10 percent alcohol (other than alcohol derived from petroleum, natural gas, or coal) is exempted from the Federal excise taxes on motor fuels on or after January 1, 1979, and before October 1, 1984. The Energy Tax Act provides that gasoline may be sold free of tax if it is to be used in the production of gasohol. The Energy Tax Act also provides that if the gasohol for which an exemption from the tax is obtained is later separated into gasoline and alcohol, the person doing such separation is to be treated as the producer of the gasoline and

[1] The other special motor fuels are benzol, benzene, naptha, liquified petroleum gas, casinghead and natural gasoline, or any other liquid (other than kerosene, gas oil, fuel oil, gasoline, or diesel fuel).

[2] See secs. 39, 6416, 6420, 6421, and 6427.

[3] These taxes are the manufacturers excise taxes on lubricating oil, trucks, truck parts, tires, tubes, and tread rubber and the tax on use of heavy highway motor vehicles (secs. 4061, 4071, 4091, and 4481).

thus would ordinarily be liable for the 4-cent-a-gallon tax. Similarly, the Energy Tax Act provides that, if gasohol is separated into diesel or other special fuels and alcohol, the separation will be treated as a sale ordinarily subject to a 4-cent tax. No provision is made for refund of the tax on gasoline if tax-paid gasoline is mixed with alcohol to produce gasohol.

Approximately 23 States also provide an exemption for gasohol from all or a portion of comparable State gasoline taxes. These exemptions range from one cent per gallon in Connecticut and Maryland to 9.5 cents per gallon in Arkansas.

Reasons for Change

In 1978 Congress concluded that it was important to encourage the development of energy sources other than petroleum products for use in motor fuels. Consequently, Congress provided that gasohol which is at least 10 percent alcohol (other than alcohol derived from petroleum, natural gas, or coal) would be exempted from the 4-cent-a-gallon Federal excise taxes on motor fuels.

On reexamination of this issue, Congress concluded that the amount of the tax incentive provided by this excise tax exemption—which confers a tax benefit approximately equal to 40 cents per gallon of alcohol—is generally appropriate. However, in many circumstances, the production of alcohol for fuel use and the subsequent distribution of the alcohol and gasohol requires substantial investment in plant and equipment. Without tax incentives which continue substantially beyond 1984, gasohol may not become competitive with gasoline. Thus, the fact that the exemption had been scheduled to expire on October 1, 1984, had apparently made many persons unwilling to invest in plant and equipment to produce alcohol for fuel use or to distribute such alcohol or gasohol.

Accordingly, Congress concluded that it was appropriate to extend the current exemption for gasohol from the Federal excise taxes on motor fuels through December 31, 1992, because such an extension appears necessary to encourage these investments.

Explanation of Provisions

The Act extends the excise tax exemption for fuels which are at least 10 percent alcohol (other than alcohol derived from petroleum, natural gas, or coal) through December 31, 1992.

The Act also makes technical amendments to the provisions relating to the definition of alcohol for purposes of this excise tax exemption. One of these amendments clarifies the law by providing that the alcohol which can be used in tax-exempt gasohol must be at least 190 proof (as previously required by Treasury regulations). Another amendment provides that for purposes of determining the percentage of a motor fuel which consists of alcohol, the volume of alcohol includes the volume of any denaturant (including gasoline) which is added under any formula approved by the Secretary of Treasury (or his delegate) to the extent that such denaturants do not exceed 5 percent of the

volume of the alcohol (including denaturants).[4] This rule also applies in measuring the volume of alcohol for purposes of the tax credits for alcohol used as fuel.[5]

The extension of the exemption in the Act does not affect current Highway Trust Fund receipts because the duration of the exemption under prior law was for the same period that the receipts from motor fuels are dedicated to the Fund (through September 30, 1984). However, when the provisions were examined by the Conference committee, considerable concern was expressed that the extension of the exemption would reduce Federal excise tax receipts which would be dedicated to the Fund in the future if Congress were to extend the Fund and the financing approach of present law.[6]

The conferees expressed their concerns with these problems in the following passage from the Statement of Managers:

> One of the major underlying issues pervading the entire conference was the question of the Highway Trust Fund. All conferees are aware of projections indicating that in the near future there will be a sizable reduction in the estimated tax receipts dedicated to the Highway Trust Fund. This includes the reduction due to the gasohol exemption contained in this conference report. The conferees are convinced that it is essential that hearings begin as rapidly as possible in the remainder of this session to consider the question of finding ways and means to restore the Highway Trust Fund to the level required to carry out its future purposes. For this reason the conferees would propose that not only should hearings be scheduled as soon as possible after the passage of the windfall profit tax legislation but also that all agencies concerned with the future of the Highway Trust Fund be allowed to provide whatever information is needed by Congress to give proper consideration to proposals for a restoration of the Highway Trust

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[4] Under prior law, the volume of ethanol which contained less than 5 percent by volume of a denaturant other than gasoline was to be treated as including the volume of the denaturant (S. Rep. No. 95–529, 46). The purpose of the change was to provide the same rule for gasoline as for other denaturants.

[5] Code sec. 44E(d)(4).

[6] As reported by the Committee on Finance, the bill would have repealed the excise tax exemption for fuels that are at least 10 percent alcohol and substituted a refundable income tax credit of 40 cents per gallon of alcohol used as a motor fuel (10 cents per gallon for alcohol produced from coal). Unlike the excise tax exemption, the credit would not have reduced the amounts in the Highway Trust Fund. In general, the income tax credit would have applied to alcohol sold or used by the producer after December 31, 1979, and before January 1, 2000, and the excise tax exemption for gasohol would have been repealed for gasohol sold or used after December 31, 1979. Consequently, under the bill as approved by the Committee on Finance, the amounts deposited in the Highway Trust Fund would have been greater than under present law.

However, a Senate floor amendment eliminated the refundable income tax credit for alcohol and the repeal of the excise tax exemption for gasohol. This amendment to the bill extended the excise tax exemption to January 1, 2000, and provided a nonrefundable income tax credit for alcohol used as (or in) fuel only where the excise tax exemption was not available.

Since the House bill had no provision relating to this excise tax exemption, the scope of conference did not include a provision which would have reduced the loss in Highway Trust Fund receipts for the period during which excise tax receipts are currently dedicated to the Fund.

Fund to its full capabilities. The conferees are aware that there is a definite need to continue and extend the life of the Highway Trust Fund not only because proper funding is needed for the repair, rehabilitation and reconstruction of our major federal arteries but also because there is need to keep our systems in proper order so that the mass transportation system of the future, which is largely dependent on the Federal Aid system, will continue in full force.

The conferees also intend that the exemption for alcohol fuels should not apply to any future increases in the taxes on gasoline or other motor fuels to the extent that such increases result in the taxes being imposed at a rate in excess of 4 cents per gallon. (H. Rept. No. 96–817, 941–2).

It is not clear that this language reflects the intent of Congress as a whole, but there is substantial evidence to indicate that it generally reflects the intent of the House of Representatives.[7]

Effective Date

These provisions generally apply to fuel sold or used after September 30, 1984, but not later than December 31, 1992.

Revenue Effect

This provision is not expected to result in significant reductions in fiscal year revenues prior to 1985. For 1985 the fiscal year revenue loss is expected to be $177 million.

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[7] See 126 *Cong. Rec.* H. 1346–56 (Daily ed. Feb. 27, 1980) (floor debate on motion to instruct conferees).

b. Nonrefundable Income Tax Credit for Blending or Use of Certain Alcohol Fuels
(Secs. 232 (b) and (c) of the Act and new secs. 44E and 86 of the Code)

Prior Law

Under prior law, no income tax credit had been provided for alcohol used as a motor fuel. However, under provisions enacted in the Energy Tax Act of 1978, motor fuel which is at least 10 percent alcohol (other than alcohol derived from petroleum, natural gas, or coal) is exempt from the 4-cent-per-gallon Federal excise taxes on motor fuels. (This exemption is discussed in more detail in the preceding section.)

Reasons for Change

Congress generally believed that the amount of the tax incentive provided by the excise tax exemption—which confers a tax benefit approximately equal to 40 cents per gallon of alcohol (for a 90 percent gasoline, 10 percent alcohol mixture)—is generally appropriate.

However, the excise tax exemption alone does not appear to give a sufficient incentive in certain situations. Under the exemption approach, the maximum benefit per unit of alcohol was obtainable for mixtures in which the alcohol constituted 10 percent. There was no incentive to make the alcohol a greater percentage of the fuel. Also, there was no incentive for tax-exempt users, or persons purchasing for tax-exempt uses, to use gasohol as opposed to regular gasoline or diesel fuel (since no excise tax would be imposed in either event). Further, there was no tax incentive to blend less than 10 percent alcohol in motor fuels although mixtures with less than 10 percent alcohol do involve some savings of petroleum fuels.

Congress concluded that these deficiencies in prior law could be alleviated by adopting provisions which provide for a nonrefundable income tax credit for alcohol (other than alcohol derived from petroleum, natural gas, or coal) used in motor fuels. The credit is reduced by the tax benefit resulting from the excise tax exemption where it is applicable. Since the credit is measured by the amount of alcohol used in these fuels, it provides additional incentives to use more than 10 percent alcohol in gasohol, provides an incentive for the use of fuel which contains less than 10 percent alcohol, and also provides incentives for the use of gasohol by tax-exempt users and for tax-exempt uses.

Explanation of Provisions

Overview

If alcohol (other than alcohol produced from petroleum, natural gas, or coal) is used as a fuel (either blended or straight) of a type suitable for use in an internal combustion engine, a nonrefundable

income tax credit is provided. In general, the credit is available to the blender in the case of blended fuels and to the user or retail seller in the case of straight alcohol fuels. The amount of the credit is 40 cents per gallon for alcohol of at least 190 proof and 30 cents per gallon for alcohol between 150 and 190 proof. No credit is available for alcohol of less than 150 proof. The credits generally are available for alcohol fuel sold or used after September 30, 1980, and on or before December 31, 1992. A 7-year carryforward of unused credits is provided except that no carryforward may be made to a year beginning after 1994. Where the fuel obtains a benefit by reason of the excise tax exemption for alcohol fuels, the credit is reduced correspondingly. An amount equal to the amount of the credit is includible in income in the year the credit is earned.

Alcohol mixture credit (blended fuels)

The Act provides an alcohol mixture credit of 40 cents (or 30 cents) for each gallon of alcohol used by the taxpayer in the production of a mixture of alcohol and gasoline or of alcohol and a special fuel which is sold by the taxpayer producing the mixture to any person for use as a fuel or is used as a fuel by the taxpayer producing the mixture. Alcohol is eligible for the credit only if the mixture is sold for use as a fuel, or used as a fuel, in a trade or business of the taxpayer. Also, a credit is not allowed with respect to any casual off-farm production of a qualified mixture. The credit is available only for the taxable year in which the sale or use as a fuel occurs.

Alcohol credit (nonblended fuels)

The Act also provides an alcohol credit of 40 cents (or 30 cents) for each gallon of alcohol which (1) is not in a mixture with gasoline or a special fuel (other than any denaturant), and (2) (*a*) is used during the taxable year by the taxpayer as a fuel in a trade or business, or (*b*) is sold by the taxpayer at retail and placed in the fuel tank of the purchaser's vehicle. Thus, in most situations in which alcohol is used as a fuel without being blended with gasoline or a special motor fuel, the credit is available to the user. But if the straight alcohol fuel is sold by the taxpayer at retail and placed in the fuel tank of the purchaser's vehicle, then the credit would be available to the retail seller, not the purchaser (or user).

Special rules and definitions

The amount of the alcohol mixture credit or the alcohol credit is 40 cents per gallon for alcohol with a proof of 190 or more and 30 cents per gallon for alcohol with a proof of at least 150 but less than 190. No credit is available with respect to alcohol with a proof of less than 150. In determining proof, the determination is to be made without regard to any added denaturants. Also, the adding of any denaturant to alcohol is not to be treated as the production of a mixture. Consequently, if alcohol is blended with a small amount of gasoline (such as 5 percent) for denaturing, the alcohol is not treated as part of a mixture to which the alcohol mixture credit would apply. Rather, it is treated as fuel to which the alcohol credit would be available to the user (or retail seller).

In determining the amount of alcohol with respect to which a credit is allowable, the volume of alcohol includes the volume of any de-

naturant (including gasoline) which is added under any formulas approved by the Secretary of the Treasury to the extent that such denaturants do not exceed 5 percent of the volume of the alcohol (including denaturants).

Under prior law (which is not significantly amended by this Act), recapture of the benefits from the excise tax exemption is provided where the gasohol or other alcohol fuels are later separated. A similar rule is provided for recapture of the alcohol mixture credit. If the credit were allowable under this section with respect to alcohol used in the production of a qualified mixture and a person either separates the alcohol from the mixture or, without separation, uses the mixture other than as a fuel, a tax is imposed on such person equal to 40 cents a gallon (or 30 cents a gallon in the case of alcohol with a proof of less than 190) for each gallon of alcohol in such mixture. Similarly, a recapture rule is provided for the alcohol credit. Since this credit is only available in the case of actual use except in the case of certain retail sellers, the recapture rule only applies where the credit is claimed by the retail seller. In such a situation, if any credit was allowable under this section with respect to the retail sale of alcohol and any person mixes such alcohol or uses it other than as a fuel, a tax equivalent to the credit allowable (i.e., 40 cents a gallon, or 30 cents a gallon in the case of low proof alcohol) is imposed on such a person. The amounts of recapture tax imposed are treated as taxes imposed by section 4081 of the Code (the excise tax on gasoline).

The provision also provides rules relating to the manner in which the credit is to be passed through subchapter S corporations and trusts. These rules are essentially the same as the rules applicable to the targeted jobs tax credit.

Relationship to alcohol fuels excise tax exemption

Under the Act, a fuel which is more than 10 percent alcohol [1] is not only eligible for the excise tax exemption (assuming the excise taxes would otherwise be applicable) but also qualifies for a credit based on the volume and proof of alcohol in the fuel. The credit would be reduced by the amount of excise tax exemption applicable to the fuel.[2]

For example, if a taxpayer blends 7,000 gallons of gasoline and 3,000 gallons of 190 proof alcohol and sells the mixture to a service

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[1] As under the excise tax exemption, the term alcohol does not include alcohol produced from petroleum, natural gas, or coal. This means that alcohol produced from such substances, or from any derivative or product of such substances, may not be treated as alcohol which is eligible for the credit (or as alcohol for purposes of the "at least 10 percent alcohol" requirement in the excise tax exemption).

[2] If no excise tax would apply to the fuel because of an exemption (or credit or refund) provision other than the exemption for alcohol fuels, the credit would not be reduced. Thus, if a taxpayer blends 90 gallons of gasoline and 10 gallons of 190 proof alcohol and sells, the mixture to a unit of local government, the sale of the fuel would be tax-free (by reason of sec. 4221(a)(4)) and the taxpayer could claim the credit on the 10 gallons of alcohol without any reduction. Similarly, if the taxpayer were to sell the alcohol fuel to a farmer for on-farm use, the taxpayer may claim the credit without reduction even though the alcohol fuel was sold free of tax to the farmer. (The basis for the result in the preceding sentence is that if a tax had been imposed on the fuel sold to the farmer, the farmer could have claimed a credit or refund of such tax (see secs. 39 and 6420).)

station, the amount of credit allowable would be $800, computed as follows: 3,000 gallons×$0.40=$1,200, reduced by $400 (10,000 gallons×$0.04). Thus, the tax benefit on a per-gallon-of alcohol basis would be the same for a fuel which is 30 percent alcohol as for a fuel which is 10 percent alcohol.

Credit carryforward

The Act provides that any credits which are not used in the taxable year in which they are earned may be carried forward for up to 7 years. However, no credit may be carried forward to a taxable year beginning after December 31, 1994.

Inclusion in income

An amount equal to the amount of credit earned by the taxpayer for the taxable year is included in the taxpayer's income for such year. The amount included in income is 40 cents (or 30 cents) per gallon of alcohol sold or used during the taxable year, and such amount is not dependent upon whether the taxpayer has sufficient income tax liability to use the entire credit for that year. The amount included in income reflects any reduction made to coordinate the credit with the excise tax exemption for gasohol.

Because the credit (like most other credits) does not reduce the tax liability computed under the alternative minimum tax for individuals, the credit is not included in income for purposes of computing the tax base under the alternative minimum tax provisions.

The reason for this income inclusion is that the benefit is intended to be generally the same as the benefit of a 4-cent-per-gallon excise tax exemption for a gallon of gasohol which is comprised of 10 percent alcohol and 90 percent otherwise taxable motor fuels.[3]

Effective Date

The provision applies to sales or uses of alcohol fuels after September 30, 1980, in taxable years ending after that date.

Revenue Effect

The fiscal year revenue loss from this provision is expected to be $1 million in 1980, $4 million in 1981 and 1982, $6 million in 1983, $8 million in 1984, and $10 million in 1985.

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[3] Because the excise tax is a deductible expense for the person on whom it is imposed (the producer in the case of gasoline or the retailer in the case of diesel fuel or special motor fuels), it is necessary to have an amount equivalent to the income tax credit (or refund) includible in income to produce the same net tax effect. Thus, for a taxpayer in the 40 percent marginal tax bracket, a 40 cent excise tax exemption is worth 24 cents after income tax since the loss of the deduction will increase income tax liability by 16 cents. Similarly a 40 cent income tax credit plus the inclusion in income of 40 cents will result in a benefit of 24 cents after income tax.

c. Credit or Refund of Excise Taxes on Tax-Paid Gasoline Used in Gasohol

(Sec. 232(d) of the bill and secs. 39, 4081(c) and 6427 of the Code)

Prior Law

Under prior law, as amended by the Energy Tax Act of 1978, gasohol was exempted from the Federal excise taxes on motor fuels on or after January 1, 1979. However, no provision was made for the refund or credit of the tax on gasoline if tax-paid gasoline was mixed with alcohol to produce gasohol. (In general, no similar problem occurs in the case of diesel fuel or special motor fuels purchased to be mixed with alcohol since the tax is imposed at the retail level and not the manufacturer level.)

The Energy Tax Act of 1978 also provided that, if the gasohol for which an exemption from the tax is obtained is later separated into gasoline and alcohol, the person doing the separating is to be treated as the producer of the gasoline and thus would ordinarily be liable for the 4-cent-a-gallon tax.

Reasons for Change

Congress believed that the failure to provide a credit or refund mechanism in the Energy Tax Act of 1978 was an oversight and makes an unwarranted distinction based on the manner in which gasohol producers acquire gasoline for mixing with alcohol to make tax-exempt alcohol fuels. Congress also believed that the recapture treatment that applies if tax-exempt gasohol is separated should apply not only if the gasoline was obtained free of tax but also if a credit or refund of excise taxes had been obtained.

Explanation of Provisions

The Act provides that if a person purchases tax-paid gasoline which is used in the production of tax-exempt alcohol fuels (including gasohol), the person may obtain a refundable income tax credit (or a payment if the amount is $200 or more during any of the first 3 quarters of the taxable year) in an amount equal to the taxes paid on such gasoline.

To prevent the allowance of more than one credit or refund of the same taxes, the Act also provides that if a refund of excise taxes on gasoline is allowable under these new provisions, no credit or refund of the taxes is allowable under any other provision of the Code.

The Act also amends the provision (sec. 4081(c)) which treats a person who separates an exempted gasoline-alcohol mixture into gasoline and alcohol as the producer of such gasoline (and who therefore

ordinarily is subject to the 4-cent-a-gallon tax), by providing that this treatment applies not only if the gasoline was originally acquired free of tax but also if a credit or refund of excise taxes had been obtained.

Effective Date

These provisions generally apply as of January 1, 1979, which is the effective date of the alcohol fuels excise tax exemption under the Energy Tax Act of 1978.

A special rule provides that any gasoline-alcohol mixture sold or used on or after January 1, 1979, and before the date of enactment (April 2, 1980) shall be treated as sold or used on the date of enactment for purposes of these credit or refund provisions. Thus, any amounts which a taxpayer may be entitled to have refunded or credited under these provisions for this pre-enactment period are to be aggregated for purposes of the $200-per-quarter test. Consequently, a calendar year taxpayer could obtain a refund of all the amounts attributable to the pre-enactment period for the quarter of his taxable year in which April 2, 1980, falls if the $200 test is satisfied (taking all these amounts into account as if the fuel had been sold or used on April 2, 1980). If this test is not satisfied, such amounts may be claimed as a credit on the taxpayer's income tax return for the taxable year in which April 2, 1980, falls.

Revenue Effect

The revenue effect from this provision is expected to be negligible.

d. Exemption From Distilled Spirits Rules for Alcohol Fuel Production Facilities
(Sec. 232(e) of the Act and new sec. 5181 and secs. 5004, 5005, 5214, and 5601 of the Code.)

Prior Law

Prior law provided a detailed regulatory scheme for distilled spirits plants and persons involved in the production of ethyl alcohol. This regulatory scheme applied to the production of alcohol for industrial uses, as well as production for human consumption. The regulatory scheme required the registration of a distillery and an investigation of the background of the individuals operating the distillery prior to its commencement of business. This scheme also required approval of the details of plant construction, provided for supervision of production by employees of the Bureau of Alcohol, Tobacco and Firearms, and required that a series of bonds be obtained by an operator of a distilled spirits plant in order to engage in the production of distilled spirits.

Reasons for Change

Congress believed that producers of alcohol to be used in gasohol should be encouraged to begin commercial production of such alcohol as soon as possible subject to the minimum amount of regulation needed to insure against violation of the alcohol taxes. The Act consequently provides a statutory framework for a reasonable relaxation of the existing regulatory rules in order to facilitate the production of alcohol for fuel purposes.

Explanation of Provisions

The Act provides special rules for distilled spirits plants used to produce alcohol for fuel. These plants may be established for the production of alcohol for fuel purposes only. The distiller may remove the alcohol free of tax from these plants only after rendering it unfit for beverage purposes. The Secretary of the Treasury is provided with broad authority to waive or reduce existing regulatory requirements for these new types of plants, such as by allowing simplified application and recordkeeping procedures, and providing reduced control and bonding requirements.

The Act provides an expedited permit application procedure (and no bond) for small producers of alcohol for fuel use. This procedure requires Treasury action within 60 days of the submission of a completed application and provides for automatic approval of applications if Treasury action is delayed. A small producer means a plant that produces no more than 10,000 proof gallons of alcohol per year.

Congress intended that these provisions of the Act not be interpreted as affecting the Treasury Department's authority, under present law, to revoke or suspend permits for distilled spirits plants.[1]

Effective Date

These provisions become effective on the first day of the first calendar month which begins more than sixty days after the date of enactment (April 2, 1980); that is, July 1, 1980.

Revenue Effect

This provision is expected to have no revenue effect.

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[1] See Code secs. 5171 and 5271.

e. Study of Imported Alcohol (Sec. 232(f) of the Act)

Prior Law

Under prior law (and the Act), the excise tax exemption for fuels which consist of at least 10 percent alcohol applies to fuels containing imported alcohol, as well as to domestically produced alcohol. Similarly, the credit provided for alcohol used in fuel by the Act (under new Code sec. 44E) applies to blenders, users, or retail sellers who blend, use, or sell either domestic or imported alcohol.

Reasons for Change

One of the goals of the Act was to encourage energy independence. Congress was concerned about making these tax incentives available to imported alcohol because the provision of such incentives to imported alcohol would tend to substitute dependence on one form of foreign energy for another and might well exacerbate the country's balance of payment problems.

However, the provision of these tax incentives in their present form only for domestically produced alcohol may be inconsistent with our obligations under trade agreements.

Explanation of Provisions

The Act directs the Secretary of the Treasury to recommend to Congress, within 180 days after the date of enactment (April 2, 1980), methods which may be used to limit the importing of alcohol into the United States for fuel purposes. The methods recommended may include (but are not limited to) denial of the excise tax exemption and the credit for alcohol fuels for fuels produced from imported alcohol, import quotas and duties, and strict surveillance of such imports to monitor their effect on the domestic fuel alcohol industry.

Effective Date

The recommendations are due on September 29, 1980 (180 days after the date of enactment, April 2, 1980).

Revenue Effect

This provision will have no revenue effect.

f. Reports on Alcohol Fuels (Sec. 232(g) of the Act and sec. 221(c) of the Energy Tax Act of 1978)

Prior Law

Section 221(c) of the Energy Tax Act of 1978 directed the Secretary of Energy, in consultation with the Secretary of the Treasury and the Secretary of Transportation, to submit to the Congress annual reports on the use of alcohol in fuel for 1980 through 1984. These reports are to include information on the use of alcohol in motor fuels, the amount of gasoline saved by the use of alcohol in fuels, and the revenue costs of the exemption for gasohol from the Federal excise taxes on motor fuels.

Reasons for Change

Congress believed that the reports should be expanded to include the impact on the Highway Trust Fund of the excise tax exemption and the revenue effect of the new alcohol fuels credits. Congress also believed that these reports should be made through 1992, the year the exemption and credits are to terminate under the Act.

Explanation of Provisions

The Act requires that the Secretary of Energy make these annual reports through 1992 and expands the scope of the reports to include the impact of the alcohol fuels tax incentives on the Highway Trust Fund. The Act also changes the report requirements to conform the statutory language to the revisions in the rules relating to tax incentives for alcohol used in motor fuels and deletes the requirement that a report be made in 1980 because of the change in the tax incentives for alcohol fuels made by the Act.

Effective Date

This provision applies to reports made from April 1, 1981, through April 1, 1992.

Revenue Effect

This provision will have no revenue effect.

4. Industrial Development Bond Provisions

a. Industrial Development Bonds for Hydroelectric Facilities (Sec. 242 of the bill and sec. 103 of the Code)

Prior Law

Under Code section 103 interest on State and local government obligations is generally exempt from Federal income tax. However, tax exemption is denied to State and local government issues of industrial development bonds with certain exceptions. A State or local government bond is an industrial development bond (IDB) if (1) all or a major portion of the proceeds of the issue are to be used in any trade or business not carried on by a State or local government or tax-exempt organization, and (2) payment of principal or interest is secured, in whole or in major part, by an interest in, or derived from payments with respect to, property used in a trade or business.

Certain industrial development bonds qualify for tax exemption where the proceeds of the bonds are used to provide exempt activity facilities. Such facilities include facilities for the local furnishing of electric energy (Sec. 103(b)(4)(E)) and facilities for the furnishing of water (Sec. 103(b)(4)(G)).

A facility for the furnishing of water will qualify as an exempt activity facility if it meets three requirements. It must be for the furnishing of water, it must be operated by a government unit or regulated public utility, and it must make water available to members of the general public.

The requirement that a facility make water available to members of the general public requires that a facility make available a substantial portion (i.e., 25 percent) of its water to the residential users in its service area. The requirement that a facility be a facility for the furnishing of water means that the facility must be used for the collection, treatment or distribution of water to a service area. Equipment which is used for the production of electric energy, such as generators or turbines, does not qualify as a facility for the furnishing of water, even where such equipment is located within a dam or reservoir which qualifies as a facility for the furnishing of water. However, a tax exempt industrial development bond may be used to finance this type of equipment if the equipment qualifies as facilities for the local furnishing of electric energy.

Under section 103(b)(4)(E) and Treasury regulations, property will qualify as a facility for the local furnishing of electric energy if it is part of a system which provides electric energy to the general populace in a service area comprising no more than two contiguous counties, or a city and one contiguous county.

In addition, in order to qualify for tax-exempt financing, a facility for the local furnishing of electric energy must satisfy a public use requirement. In general, this provision requires that a facility serve or be available on a regular basis for general public use. (Treas. Reg. sec. 1.103–8(a)(2)). A facility for the local furnishing of electric energy will, in general, satisfy this requirement only if such facility or the output from it is available for use by members of the general public. (Treas. Reg. sec. 1.103–8(f)(1)(i)).

Treasury regulations provide that the public use requirement with respect to a facility for the local furnishing of electric energy will be satisfied if (1) the owner or operator of the facility is obligated, by a legislative enactment, local ordinance, regulation, or the equivalent thereof, to furnish electric energy to all persons who desire such services and who are within the service area of the owner or operator of such facility, and (2) it is reasonably expected that such facility will serve or be available to a large segment of the general public in such service area. (Treas. Reg. sec. 1.103–8(f)(1)(ii)).

Reasons for Change

Congress considered a number of proposals which were designed to reduce the consumption of oil and gas. Among those proposals there were several tax incentives which provided for the hydroproduction of electricity. Many of these potential hydroelectric sites include low-head dams which are not currently producing electricity. In addition, other potential sites exist which could be used to generate electricity without the construction of a dam or the impoundment of water. However, the generating capacity of these sites is relatively small (i.e., less than 125 megawatts). As a consequence of the higher operating cost per kilowatt hour of electricity generated and the current high interest rates, Congress believed that tax incentives were necessary to encourage the development of these low head hydroelectric projects.

On the other hand, larger hydroelectric facilities which enjoy the advantage of lower operating costs per kilowatt hour of electricity generated and other economies of scale are being developed currently or are currently economically feasible. In light of these factors, Congress decided that, while it was appropriate to provide tax incentives to encourage the development of small-scale hydroelectric facilities, such incentives were not necessary in the case of large hydroelectric facilities. In addition, in order to avoid any adverse environmental effects on the nation's rivers and streams, Congress decided to limit the application of tax incentives to hydroelectric facilities which do not involve the impoundment of water and to small-scale dams in existence on October 18, 1979.

Congress reviewed the provisions of prior law which provide tax-exempt financing for electric energy facilities. In general, Congress concluded that it would be inappropriate to expand the use of tax-exempt financing for such facilities. In reaching this conclusion, Congress recognized that the Federal subsidy which a tax exempt obligation provides is less efficient than the subsidy provided through investment tax credits. As a result, Congress concluded that, in those cases in which it was desirable to subsidize the construction of electric energy

facilities through the tax laws, it would provide the subsidy generally through investment tax credits. However, Congress recognized that credits and deductions do not provide any subsidy to State and local governments because they are not subject to Federal income tax, and that industrial development bonds could be used to provide subsidies to these entities.

Explanation of Provision

The Act provides that interest on an industrial development bond, substantially all the proceeds of which are to be used to provide qualified hydroelectric generating facilities, is exempt from Federal income taxation provided that the public use test of present law is satisfied. A qualified hydroelectric generating facility is defined as qualified hydroelectric generating property which is owned for tax purposes by a State, a political subdivision of a State, or an agency or instrumentality of a State or political subdivision of a State (i.e., a governmental body), and is installed at a qualified hydroelectric site.

Qualified hydroelectric site

A qualified hydroelectric site, in general, means any site which has an installed capacity of less than 125 megawatts (1) at which there is a dam the construction of which was completed prior to October 18, 1979, and which is not significantly enlarged after such date or (2) at which electricity is to be generated without any dam or other impoundment of water. For this purpose, the installed capacity is to include any additional capacity added during the three taxable years following the taxable year in which the equipment financed with the IDB is placed in service. A qualified hydroelectric site includes only sites which are located on a natural water course or constructed water flow and which generate electric energy from the flow or fall of water. The provision does not apply to pumped storage facilities, ocean thermal facilities or ocean tidal facilities.

Existing dam sites.—A qualified hydroelectric site includes certain Government owned dams where the construction of the dams was completed prior to October 18, 1979, and the dam was not significantly enlarged after such date. A dam site described in this section generally includes dams which are currently being used in connection with the generation of electricity, dams which have been used in connection with the generation of electricity in the part, and dams which have never been used in connection with the generation of electricity. In addition, a dam site or other impoundment site includes any water passageways that are fed from the water behind the dam or other impoundment, if the primary purpose of the water passageways is for the generation of electricity.

A dam, the construction of which was completed on or before October 18, 1979, means any dam or barrier built across a watercourse or other manmade structure for the impoundment of water, which was completed on or before October 18, 1979, and which does not require any significant construction or enlargement of the impoundment structure (other than repairs or reconstruction) in connection with the installation of the hydroelectric power project. For purposes of this section, the construction of penstocks, powerhouses, fish passageways

and similar structures, does not constitute significant construction or enlargement of the impoundment structure. In addition, the reconstruction or repair of breached structures which increases the water level or impoundment of a dam to its original or designed levels will not constitute significant construction or enlargement of the impoundment structure if the reconstruction or repair were undertaken in order to strengthen a dam or to eliminate leakage. On the other hand, construction which extends a dam or increases the height of a dam for purposes of increasing the water level or impoundment will constitute significant construction or enlargement of the impoundment structure.

Any site at which there is a dam will not, however, be a qualified hydroelectric site unless the dam is owned for tax purposes by one or more governmental units on October 18, 1979, and during the entire period the obligations are outstanding.

Non-dam sites.—A site at which electricity is to be generated without any dam or other impoundment of water includes conduit sites, such as flood control, sewage treatment flows, irrigation water flows, other similarly constructed water flows, and natural water flows, such as rivers and streams. In the case of a conduit site, the construction of the site may be completed either before or after October 18, 1979. For purposes of this provision, the generation of electricity at the site of a gate or other water control structure in an irrigation ditch or canal is not treated as generation at the site of a dam or water impoundment.

Qualified hydroelectric generating property.—Under the Act, tax-exempt IDBs can be issued to finance government owned qualified hydroelectric generating property. Qualified hydroelectric generating property means (1) equipment for generating electric energy from water and (2) structures for housing such equipment, fish passageways and dam rehabilitation property which are required by reason of the installation of electrical generation equipment at the qualified hydroelectric site.

In order to be eligible for tax-exempt IDB financing, the qualified hydroelectric generating property must be owned for Federal tax purposes by a State, political subdivision thereof, or agency or instrumentality of any of the foregoing for as long as the tax-exempt IDBs are outstanding. However, the property financed with a tax exempt IDB under this provision does not have to be owned by the same governmental unit that issues the bonds. Moreover, the facility may be jointly owned by a governmental unit and private party. However, the tax-exempt financing under this provision will only be available to the extent of the governmental unit's interest in the qualified hydroelectric site.[1]

Qualified hydroelectric generating property includes generating equipment such as turbines and generators. It includes the capital costs for repairing or restoring existing nonfunctional generating equipment. However, such equipment only includes equipment up to the transmission stage.

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[1] Where the requirements of Code sections 46 and 48 are satisfied, the private parties will be eligible for an investment tax credit and an energy tax credit with respect to their share of the qualified expenditures for the project.

In addition, qualified hydroelectric generating property includes structures (such as powerhouses and similar structures) for housing generating equipment, fish passageways (and related equipment such as fish counters), and dam rehabilitation property, but only if such equipment is required by reason of the installation of generating equipment. The term dam rehabilitation property includes property for the reconstruction of breached structures and renovation of machinery and structural elements which have been left in place. It includes the cost of reconstruction or rehabilitation of a dam which impounds water for use by the generating equipment, such as the costs of strengthening the dam and eliminating leakage. However, it does not include the costs for extending or increasing the height of the dam for purposes of increasing the water level or the size of the impoundment. Furthermore, in the case of an impoundment which does not meet state or federal spillway capacity or other requirements, the term dam rehabilitation property includes the replacement of the entire impoundment structure. However, in the case of non-dam sites, qualified hydroelectric generating property does not include the cost of the structures which create or contain the water course or flow.

Installed capacity fraction

Under the Act, the entire qualified hydroelectric generating facility may be provided with tax-exempt IDBs where the total installed capacity of the site does not exceed 25 megawatts. However, only a portion of a qualified hydroelectric generating facility with an installed capacity in excess of 25 megawatts, but less than 125 megawatts, may be provided with tax-exempt IDBs. The portion may not exceed the eligible cost of the facilities being provided (in whole or in part) from the proceeds of the bond issue (i.e., the qualified hydroelectric generating property and the functionally related and subordinate property to be installed) multiplied by a fraction the numerator of which is 25 reduced by 1 for each whole megawatt by which the installed capacity exceeds 100 megawatts, and the denominator of which is the number of megawatts of installed capacity (but not in excess of 100).

This may be illustrated by the following example. Assume that a municipality enters into a joint venture with a private concern to install 40 additional megawatts of generating capacity at an existing dam owned by the municipality, at which 10 megawatts of generating capacity now exist. The cost of the entire project is $30 million of which $20 million is qualified hydroelectric generating property and functionally related and subordinate equipment. The municipality and the private concern are equal joint venturers, and the municipality's share of the cost of the qualified hydroelectric generating facilities is $10 million. Under this limitation, the amount of qualified hydroelectric generating property is $5 million (i.e., 25 divided by 50 multiplied by $10 million).

In computing this limitation, there is to be taken into account the amount of proceeds of any prior issues (whether or not the same issuer is the issues of this issue and whether or not that prior issue was an industrial development bond) which are used to finance the same facilities and which are still outstanding at the time of issuance of this issue. However, the amount of any such proceeds are not to be taken into

account to the extent that the prior issue is to be redeemed from the proceeds of this issue.

These rules may be illustrated by the following example. Assume that a municipality issued tax-exempt IDBs in 1967 in the amount of $50 million to finance the reconstruction of hydroelectric generating facilities with installed capacity of 25 megawatts. In 1982, the municipality plans to issue additional obligations in the amount of $60 million for additional hydroelectric generating facilities at that site which would increase at the installed capacity to 50 megawatts. Because the 1967 issue which provided facilities at the same site is still outstanding, the amount of the proceeds of that issue must be taken into account in determining the installed capacity fraction. Thus, the amount of tax-exempt bonds that can be issued is $5 million (25 megawatts divided by 50 megawatts multiplied by $110 million, or $55 million, less $50 million).

Miscellaneous

The Act provides that tax exempt IDBs may be used to provide qualified hydroelectric generating facilities at two existing dams in Grant County, Washington, the installed capacity of which is more than 125 megawatts. Under this provision, the entire qualified hydroelectric generating facility may be provided with tax exempt IDBs.

Finally, the Act provides two additional rules (relating to registration, and guaranteed or subsidized loans) with respect to IDB's used to provide qualified hydroelectric generating facilities. (See the description of sec. 244 of the Act in section d. below.)

Effective Date

The provision applies with respect to obligations issued after October 18, 1979.

The eligible cost of the facilities being provided is the portion of the total cost of the facilities which may be reasonably expected to be the cost to the government body and is, in general, attributable to periods after October 18, 1979, and before January 1, 1986. However, in the case of an application which has been docketed by the Federal Energy Regulatory Commission before January 1, 1986, eligible costs include the portion attributable to periods after October 18, 1979, and before January 1, 1989.

Revenue Effect

The revenue loss is expected to be $1 million in fiscal year 1982, $7 million in 1983, $10 million in 1984, and $13 million in 1985.

b. Industrial Development Bonds for Solid Waste Disposal Facilities (Sec. 241 of the Act and sec. 103 of the Code)

Prior Law

Under Code section 103, interest on State and local government obligations is generally exempt from Federal income tax. However, tax exemption is denied to State and local government issues of industrial development bonds, with certain exceptions. A State or local government bond is an industrial development bond if (1) all or a major portion of the proceeds of the issue are to be used in any trade or business not carried on by a State or local government or tax-exempt organization, and (2) payment of principal or interest is secured, in whole or in major part, by an interest in, or derived from payments with respect to, property used in a trade or business.

Industrial development bonds qualify for tax exemption if substantially all of the proceeds of the bonds are used to provide exempt activity facilities. Such facilities include solid waste disposal facilities and facilities for the local furnishing of electric energy (Code sec. 103(b)(4)(E)). However, the Internal Revenue Service has taken the position that if the financed facilities are to be acquired or used by an agency or instrumentality of the United States Government, the United States Government is the true obligor of the obligation, and the obligation is not tax exempt as the bonds are not industrial development bonds. (Rev. Rul. 73–516, 1973–2 C.B. 23.)

Solid waste disposal facilities are defined in Treasury regulations as property used for the collection, storage, treatment, utilization, processing or final disposal of solid waste. A facility which disposes of solid waste by reconstituting, converting or otherwise recycling it into material which is not waste will qualify as a solid waste disposal facility if at least 65 percent of the material introduced into the recycling process is solid waste (Treas. Reg. sec. 1.103–8(f)(2)). However, in the case of property which has both a solid waste disposal function and a function other than the disposal of solid waste, only the portion of the cost allocable to the solid waste disposal function will be treated as an expenditure for a solid waste disposal facility. (Temp. Treas. Reg. sec. 17.1(a)).

The regulations further provide that a facility which otherwise qualifies as a solid waste disposal facility will not be treated as having a function other than solid waste disposal merely because material or heat which has utility or value is recovered or results from the disposal process. Where materials or heat are recovered, the waste disposal function includes the processing of such materials or heat in order to put them into the form in which the materials or heat are in fact sold or used, but the waste disposal function does not include further proc-

essing which converts the materials or heat into other products. The regulations provided an example of qualifying solid waste disposal facilities. In the example, solid waste is processed in a manner which removes glass and metals. The remaining solid waste is burned, and the resulting heat is used to produce steam. The example provides that the boiler used to produce the steam qualifies as a solid waste disposal facility. The example also provided that pipes used to transport the steam and generating equipment used to transform the steam into electric energy are not solid waste disposal facilities.

Although electric generation equipment generally would not qualify as solid waste disposal facilities, a tax-exempt industrial development bond may be used to finance such equipment if the facilities qualify as facilities for the local furnishing of electric energy.

Under section 103(b)(4)(E) and under Treasury regulations, property will qualify as a facility for the local furnishing of electric energy if it is part of a system which provides electric energy to the general populace in a service area comprising no more than two contiguous counties, or a city and one contiguous county.

Reasons for Change

The present Treasury regulations permit tax-exempt financing of facilities which are used to burn solid waste to produce steam. However, under present technology, it is often more feasible to process the solid waste so that a cellulose fiber is produced. This cellulose fiber may have a value in the area where it is produced because it can be burned as a substitute for coal, oil, or natural gas.

Congress believed that tax-exempt financing should not be denied where it is technologically more feasible to process the solid waste before burning it, instead of burning it before processing, so long as the processing and burning are part of the same integrated process of solid waste disposal. However, Congress believed that tax-exempt financing should not be allowed for facilities simply because the fuel they burn is derived from solid waste. Consequently, the Congress believed that the tax-exempt financing should, in general, be allowed for facilities which burn the cellulose fiber which is derived from solid waste, regardless of whether such material has utility or value, so long as the facilities used in the processing of solid waste and those facilities used in the production of steam from fuel derived from solid waste comprise an integrated solid waste disposal facility. In order to achieve these objectives, the Act continues to allow tax-exempt financing as under prior law for facilities which produce steam from the burning of solid waste derived from materials which have no utility or value, and the Act provides a new provision which allows tax-exempt financing for qualified steam generating facilities and qualified alcohol producing facilities which use solid waste derived materials which have utility or value (i.e., fuel derived from solid waste).

Explanation of Provision

Under the Act, the term solid waste disposal facility is defined to include a qualified steam-generating facility and a qualified alcohol producing facility, as defined below. As a consequence, tax-exempt

IDBs may be used to finance such facilities. In addition, the Act allows tax-exempt bonds to be issued for certain solid waste-energy producing facilities. Congress intended that any IDB provision of this section of the Act which requires that a particular person owns facilities means that the facilities must be owned for tax purposes by that person. Congress intended that if facilities are solid waste disposal facilities under the provisions of this Act or under prior law, the amount of their cost which may be financed with tax-exempt IDBs is not to be reduced by the value of any product of the solid waste disposal facilities.

Finally, Congress intended that solid waste disposal facilities may be financed with tax-exempt IDBs under the provision of this Act or under the provision of Code section 103(b)(4)(E). For example, a facility which burns solid waste and generates steam could be financed with tax-exempt IDBs if it meets the requirements of Code section 103(b)(4)(E). Further, a facility which burns fuel derived from solid waste and generates steam could be financed with tax-exempt IDBs if it meets the requirements of new Code sections 103(g) and (h).

Qualified steam-generating facilities.—A steam generating facility generally includes incinerators, boilers, smokestacks, and precipitators and other property used in the generation of steam, but not property used in the transmission of steam. However, "qualified steam generating faciilties" must meet two additional requirements.

The first requirement is that more than half of the fuel (determined on a Btu basis) used in the generation of steam must be solid waste derived fuel or a mixture of solid waste derived fuel and solid waste. The second requirement is that substantially all of the solid waste derived fuel which is used at the steam-generating facility must be produced at a facility which is located at or adjacent to the site of the steam-generating facility, and both facilities must be owned and operated by the same person.

The Act also provides a special rule for steam generating facilities owned by a State or political subdivision of a State. Under the special rule, the second requirement is deemed satisfied if substantially all the solid waste derived fuel used at the steam generating facility is produced at a facility which is owned and operated by or for the same State, or same political subdivision or subdivisions of a State, which owns the steam generating facility, and if substantially all the solid waste processed in the facility for producing solid waste derived fuel is collected from the area in which the steam generating facility is located. For example, if a county solid waste authority owns and operates a steam generating facility and substantially all the solid waste processed at the facility for producing solid waste derived fuel is collected from within the county in which the steam generating facility is located, then such facility satisfies the second requirement even though the solid waste derived fuel is produced at a facility owned and operated by such authority but located elsewhere. This requirement is also satisfied in the case of a solid waste authority having jurisdiction with respect to a metropolitan area lying in two contiguous States which owns and operates a steam generating facility located in that metropolitan area if substantially all the solid waste processed in the

facility for producing solid waste derived fuel (which is owned and operated by such authority) is collected from within that metropolitan area.

Qualified alcohol producing facility.—The term "qualified alcohol producing facility," in general, means a facility for the production of alcohol which meets three requirements. Such a facility will include property required to convert cellulose fiber into sugar and property required in the fermentation of the sugar whether those processes occur in one or more steps. It will also include property used in the distillation of the fermented solution.

The first requirement is that the primary product obtained from the facility must be alcohol. The second requirement is that more than half of the feedstock (determined on a reasonable basis, e.g., sugar content) used in the production of alcohol must be a feedstock derived from solid waste or a mixture of feedstock derived from solid waste and solid waste. The third requirement is that substantially all the solid waste derived feedstock used at the alcohol producing facility must be produced at a facility located at or adjacent to the site of the alcohol producing facility, and the solid waste derived feedstock production facility must be owned and operated by the same person who owns and operates the alcohol producing facility.

The Act also provides a special rule for certain alcohol facilities. A facility for the production of alcohol from solid waste which satisfies this special rule will not be required to meet the third requirement for a "qualified alcohol producing facility." A facility will satisfy the special rule where two conditions are satisfied. First, substantially all the solid waste derived feedstock for the facility must be produced at a facility which (i) went into full production during 1977, (ii) is located within the limits of a city, and (iii) is located in the same metropolitan area as the alcohol-producing facility. The second condition is that prior to March 1, 1980, there have been negotiations between a governmental body (e.g., a governmental authority) and an organization described in section 501(c)(3) of the Code with respect to the utilization of a special process for the production of alcohol at the facility. The special rule applies only in the case where the aggregate amount of obligations issued (by reason of this special rule) with respect to a project do not exceed $30 million, and such obligations are issued prior to January 1, 1986.

Solid waste-energy producing facility.—The Act also provides that an obligation issued by an authority for two or more political subdivisions of a State which is part of an issue substantially all the proceeds of which are to be used to provide solid waste-energy producing facilities shall be treated as a tax-exempt obligation of a political subdivision of a State which meets the requirements of an exempt activity of section 103(b)(4)(E) of the Code. For purposes of this provision the phrase "substantially all the proceeds of which are to be used to provide" is intended to have the same meaning as that phrase has under section 103(b)(4) of the Code.

A solid waste-energy producing facility means a solid waste disposal facility and a facility for the production of steam and electric energy where three requirements are met. First, substantially all the fuel for

the steam and electric energy facility must be derived from solid waste processed in the solid waste disposal facility. Second, both the solid waste disposal facility and the steam and electric energy facility must be owned and operated by the authority which issues the obligations. For this purpose, a facility will be considered operated by the authority where the authority enters into a management agreement with a private concern under which the private concern will operate the facility so long as the duration of the management contract (including any options) does not exceed one year. Third, all the steam and electric energy produced at the facility (and not used by the facility) must be sold for purposes other than for resale to an agency or instrumentality of the U.S. Government.

For purposes of this provision, a steam and electric energy facility includes incinerators, boilers, precipitators, smokestacks, internal steam distribution lines, turbines, generators and other equipment for generating steam and electric energy, and structures for housing such equipment. However, a steam and electric energy facility would only include equipment up to the transmission stage.

Congress also made clear that nothing in this provision or in the additional rules relating to Federal guarantees and federally subsidized loans is intended to affect the question under present law as to whether interest on an obligation issued by a State or local government is tax-exempt where repayment of the principal and interest on such obligation is secured or guaranteed by the Federal Government or where the Federal Government uses part or all of the financed facility. Furthermore, nothing in this provision is to be construed to override the arbitrage limitations of section 103(c) of the Code.

Additional rules.—The Act provides that all IDBs issued pursuant to the provisions of this Act are required to be issued in registered form as to principal and interest for the entire life of the obligation. Any such obligation which is not issued in registered form will not be tax-exempt.

In addition, the Act provides an additional rule in the case of IDBs used to provide qualified steam generating facilities and qualified alcohol producing facilities. Under this rule, any such obligation will not be tax-exempt where (1) the payment of principal or interest is guaranteed (in whole or part) directly or indirectly by the United States government or any agency or instrumentality thereof under a program, a principal purpose of which is to encourage the conservation or production of energy, or (2) any part of the payment of principal or interest is to be made (in whole or part) directly or indirectly with funds provided under a Federal, State or local program, a principal purpose of which is to encourage the conservation or production of energy.

Effective Date

The provision applies with respect to obligations issued after October 18, 1979.

Revenue Effect

The revenue loss is expected to be $1 million in fiscal year 1981, $4 million in 1982, and $5 million in 1983, 1984 and 1985.

c. Industrial Development Bonds for Renewable Energy Property (Sec. 243 of the Act and Sec. 103 of the Code)

Prior Law

Under Code section 103, interest on State and local government obligations generally is exempt from Federal income taxation. However, with certain exceptions, interest on industrial development bonds (IDBs) is not exempt from Federal income taxation.

A State or local government obligation, in general, will be treated as an IDB where more than 25 percent of the proceeds of an issue are to be used in the trade or business of one or more nonexempt persons, and where payment of principal or interest on the issue is secured, in major part, by an interest in, or derived from payments with respect to, property used in a trade or business.

Certain industrial development bonds qualify for tax exemption where the proceeds of the bonds are used to provide exempt activity facilities. Such facilities include sewage and solid waste disposal facilities, airports, docks, wharves, and mass commuting facilities, air and water pollution control facilities, and facilities for the local furnishing of electric energy or gas. In addition, certain small issue industrial development bonds are tax-exempt.

In general, IDBs used to provide property used to produce energy are not tax-exempt unless the issue qualifies as an exempt small issue, or the property qualifies as facilities for the local furnishing of electric energy or gas. Property, in general, will qualify under the local furnishing requirement if it is part of a system which provides electric energy or gas to the general populace in a service area comprising no more than two contiguous counties. An exempt small issue generally is an issue not more than $10 million.

In addition, Code sections 44C and 46 provide a residential energy credit and a business energy investment credit with respect to the installation of certain types of property. The residential energy credit, in general, applies with respect to (1) insulation and certain other energy-conserving components, and (2) renewable energy source property. The business energy investment credit applies, in part, to solar or wind energy property and to certain types of geothermal equipment.

Reasons for Change

Congress reviewed the provisions of prior law which provide tax incentives for energy-related expenditures. Congress decided that it would be consistent with its general policy to encourage energy conservation and the development of alternative sources of energy to authorize the use of tax-exempt bonds for renewable energy property in the case of certain State renewable energy programs approved by a State prior to October 18, 1979.

Explanation of Provision

The Act provides that interest on industrial development bonds (IDBs) which are part of an issue substantially all the proceeds of which are used to provide renewable energy property will be exempt from Federal income taxation where four conditions are satisfied. First, the obligations must be general obligations of a State. Second, the State constitutional or legislative authority granting a State the power to issue such obligations must require that taxes be levied in sufficient amount to provide for payment of principal and interest on such obligations. In order to satisfy this requirement, such taxes must be the type of tax for which a deduction would be allowed under section 164 of the Code. Third, the amount of all obligations (whether or not IDB's) under the program for renewable energy property issued by a State which are outstanding at any time may not exceed the smaller of $500 million or one-half of one-percent of the value of all property within the State. Finally, the exemption for interest on State obligations for renewable energy property shall only apply to obligations issued pursuant to a State program to provide financing for renewable energy property in a State whose legislature approved before October 18, 1979, a constitutional amendment which specifically allowed general obligation bonds of the State to be used to finance renewable energy property. The requirements of this condition will be satisfied even if a State program to provide financing for renewable energy property is in fact established pursuant to a constitutional amendment approved subsequent to October 18, 1979, so long as the legislature in the State authorizing such program had approved before October 18, 1979, a constitutional amendment which specifically allowed general obligation bonds of the State to be used to finance renewable energy property. Congress understands that these four requirements are met by the renewable energy source program in the State of Oregon.

The Act also provides that renewable energy property means any property used to produce energy (including heat, electricity, and substitute fuels) from renewable energy resources (such as wind, solar, geothermal, biomass, waste heat, or water).

Congress also intended that for purposes of this provision, the phrase "substantially all the proceeds of which are to be used to provide" is to have the same meaning as this phrase has under sec. 103(b)(4) of the Code. Finally, the Act provides two additional rules (relating to registration, and guaranteed or subsidized loans) with respect to obligations used to provide renewable energy property. (See section 244 of the Act.)

Effective Date

The provision applies with respect to obligations issued after April 2, 1980.

Revenue Effect

The revenue loss is expected to be $1 million in fiscal year 1981 and 1982, $3 million in 1983, $5 million in 1984 and $7 million in 1985.

d. Registration Requirement and Rules Relating to Energy Guarantees or Energy Subsidies (Sec. 244 of the Act and sec. 103 of the Code)

Prior Law

Under prior law, there was no general provision that denies tax exemption to interest on State or local government obligations if the obligations are guaranteed by the Federal Government. Under former Code section 103(f) (presently sec. 103(g)), interest on an obligation of the City of New York is taxable where the principal or interest on the obligation is guaranteed in whole or in part by the Federal Government. Finally, under prior law, State and local government obligations were not required to be issued in registered form in order for the interest on them to be tax exempt under section 103.

Reasons for Change

Congress became aware that unregistered tax-exempt obligations were used as a vehicle to avoid Federal estate taxes. In some cases, such obligations were removed from the decedent's possessions and were not included in the decedent's estate tax return. Because such obligations were not registered, it was difficult to establish that the decedent owned the obligations. Congress believed that requiring tax-exempt obligations to be in registered form would provide a method of establishing ownership by the decedent.

In addition, registration will further efforts to obtain compliance with Federal and State income tax laws and to detect illegal activities. In certain cases, individuals have failed to report and pay taxes due with respect to amounts includible in gross income, especially income from illegal sources. In order to avoid detection, these individuals have purchased unregistered tax-exempt obligations with the unreported income. The fact that the obligations are not registered (and the fact that no reporting requirement exists for the interest paid on such obligations) has hampered efforts to determine correctly the taxable income of these individuals. Congress believes that registration of tax-exempt obligations will remove the use of these investments as a means of avoiding detection of illegal activities and will improve the ability of the Internal Revenue Service to administer the income tax laws.

Finally, while Congress did not believe it was appropriate to extend the registration requirement to all tax-exempt obligations at this time, it believed that a registration requirement should be imposed on the new types of IDBs.

In addition, Congress believed that it was not appropriate to extend tax exemption to obligations which are either guaranteed by the Federal Government or are subsidized under a Federal, State or local

government plan. In the case of Federal guarantees, Congress was concerned that State or local government obligations should not become more attractive than the Federal Government's own obligations by reason of having both the interest on the obligations exempt from Federal income tax and the credit backing of the Federal Government. In the case of both guarantees and subsidies, Congress recognized that many of the laws it and the States enact, and programs it and the States authorize, overlap. In such cases, even though each law or program is designed individually to encourage the conservation or development of energy, the laws or programs in operation actually provide multiple benefits. This overlap results in unnecessary revenue losses from redundant subsidies and contributes to an inefficient allocation of resources. In these cases, Congress believed that taxpayers should be able to choose the particular incentive which would be most beneficial. However, Congress believed that it would be inappropriate and inefficient to allow taxpayers to use more than one of the programs provided under Federal or State laws. As in the case of registration, Congress believed it would be inappropriate to extend these rules to all tax-exempt obligations. However, it did believe that the new restrictions should apply to all new types of IDBs authorized in this Act.

Explanation of Provision

The Act provides that all IDBs issued pursuant to the provisions of this Act are required to be issued in registered form as to principal and interest for the entire life of the obligation. Any such obligation which is not issued in registered form will not be tax-exempt.

Under the guaranteed or subsidized loan restrictions, any obligation used to provide qualified hydroelectric generation property, a qualified steam-generating facility, a qualified alcohol-producing facility or renewable energy property will not be tax-exempt where (1) the payment of principal or interest is guaranteed (in whole or in part) directly or indirectly by the United States Government or any agency or instrumentality thereof under a program a principal purpose of which is to encourage the conservation or production of energy, or (2) any part of the payment of principal or interest is to be made (in whole or in part) directly or indirectly with funds provided under a Federal, State, or local program a principal purpose of which is to encourage the conservation or production of energy.

Effective Date

This provision applies to obligations issued after October 18, 1979.

5. Tertiary Injectants
(Sec. 251 of the Act and new sec. 193 of the Code)

Prior Law

Under prior law, the income tax treatment of expenditures for some tertiary injectants was unclear.

Reasons for Change

Congress decided to clarify the tax treatment of tertiary recovery expenses and encourage the use of tertiary recovery processes by allowing expenditures for qualifying tertiary injectants to be deducted, for income tax purposes, in the taxable year in which the injectants are injected into the reservoir.

Explanation of Provision

The Act provides that "qualified tertiary injectant expenses" are deductible in the taxable year in which the tertiary injectant is injected into the reservoir. "Qualified tertiary injectant expenses" are any expenditures paid or incurred during the taxable year, regardless of whether they otherwise are chargeable to capital account, for a tertiary injectant which is used as part of a tertiary recovery method. However, the term "qualified tertiary injectant expenses" does not include the cost of hydrocarbon injectants which are recoverable.

For purposes of the deductibility of qualified tertiary injectant expenses, tertiary recovery methods generally are those eligible for use in a qualified tertiary recovery project, as defined under the windfall profit tax (sec. 4993 of the Code). In addition, tertiary recovery methods include any other method for tertiary enhanced recovery of oil that is approved by the Secretary specifically for the purpose of deducting qualified tertiary injectant expenses. However, expenses for injectants used in methods approved by the Secretary under the windfall profit tax do not qualify for deductibility unless also specifically approved for purposes of this provision.

The provisions of the Act do not apply to expenditures for hydrocarbon injectants which are recoverable. Hydrocarbons include all forms of natural gas or crude oil (including synthetic hydrocarbons). This exclusion of hydrocarbon injectants also applies to any injectant which is comprised, by blend, mixture, or chemical bonding, of more that an insignificant amount of natural gas or oil. In these instances, the exclusion applies regardless of whether such a tertiary substance is injected separately, as a component of another tertiary injectant, or as a tertiary drive medium. However, any portion of a hydrocarbon injectant which is established by the taxpayer not to be a hydrocarbon is not treated as such. In addition, the exclusion of hydrocarbon injec-

tants does not apply to tertiary injectants which are hydrocarbon-based (or derived) and which are not comprised of more than an insignificant amount of natural gas or oil.

Although the provision generally is inapplicable to the cost of hydrocarbon injectants, it may apply to the extent that the taxpayer establishes that such an injectant is not ultimately recoverable from the reservoir. If this is not established, the cost of the injectant must be capitalized and recouped through depreciation or, if appropriate, inventoried and written off when consumed. Any unrecovered amount of such capitalized expenditures could be deducted as a loss in the taxable year in which it is established that the injectant has ceased benefiting production or in which the tertiary project is abandoned.

The provision is inapplicable to any cost which is subject to the section 263 intangible drilling cost election, or to any expenditure which otherwise is deductible under the Internal Revenue Code. In addition, the provision simply does not apply to any secondary recovery costs; e.g., waterflooding expenses. These costs remain subject to the generally applicable income tax rules.

Expenditures to which the provision applies are subject to recapture as ordinary income under sections 1245 and 1250 of the Code.

Although the income tax treatment of qualified tertiary injectant expenses is not elective, such expenses may be treated as having been capitalized for purposes of the windfall profit tax's 90-percent net income limitation.

This provision is intended to create no inference as to the proper categorization of tertiary injectant expenditures prior to the effective date of this provision.

Effective Date

This provision is effective for taxable years beginning after December 31, 1979.

Revenue Effect

The revenue loss is estimated to be $4 million in fiscal year 1980, $14 million in 1981, $9 million in 1982, $8 million in 1983, $7 million in 1984 and $6 million in 1985.

D. LOW-INCOME ENERGY ASSISTANCE

(Title III of the Act)

Prior Law

The fiscal year 1980 continuing resolutions (P.L. 96–86 and P.L. 96–123) and Interior appropriations (P.L. 96–126) legislation, coupled with authority contained in section 222(a)(5) of the Economic Opportunity Act, provided for a three-part, $1.6 billion program of energy assistance to low-income households for fiscal year 1980.

The first part of the program provided $400 million for direct payments to recipients of Supplemental Security Income. The remaining parts provided $800 million and $400 million to States for general energy assistance and crisis energy assistance, respectively. Funds were allocated among the States on the basis of numbers of SSI recipients, heating degree days, population below 125 percent of the poverty line, and 1978 and 1979 change in home heating expenditures. Funds under the general and crisis energy assistance portions of the program were distributed under State plans subject to approval by the Secretary of Health, Education and Welfare and the Community Services Administration, respectively.

Reasons for Change

Energy costs have risen substantially over the past few years, and particularly so in the past year. Congress was concerned that ordinary mechanisms for adjusting income assistance programs to rising costs of living may be inadequate to meet the extraordinary increases which have taken place in energy costs, particularly because energy costs for many low-income households may represent a large and vitally important element of their budgets. Thus, Congress believed that it was essential to continue to provide, for fiscal year 1981, a special program to assist low-income households in coping with the rapid increase in heating and cooling costs. The program authorized in the Act provides for a single program of block grants to States, which the States will be able to administer more effectively than the three-part program in effect for fiscal year 1980.

Explanation of Provision

The Act authorizes the appropriation of $3 billion plus certain additional amounts for fiscal year 1981 for a program of block grants to the States to provide assistance to lower-income families for heating and cooling costs.

Eligible households

Eligibility is restricted to households who have income less than the Bureau of Labor Statistics lower living standard. The BLS lower liv-

ing standard, which is currently used in various eligibility determinations under the Comprehensive Employment and Training Act (CETA) program, is adjusted by family size and geographic location. The national average amount for a 4-person family for 1980 is $12,585.

In addition, States may give assistance, regardless of income, to households which receive food stamps, aid to families with dependent children (AFDC), needs-tested veterans' pensions, or supplemental security income (SSI), except for SSI recipients who live in another household and whose benefits are therefore reduced, SSI children living with non-SSI parents, and SSI recipients living in Medicaid institutions.

States are not required to provide a benefit to every household defined as an eligible household, but the funds authorized in this program may not be used to provide benefits to households not included in this definition.

Allotments to States

Ninety-five percent of the amount appropriated under the $3 billion authorization is allotted by various formulas to the 50 States and the District of Columbia. The basic formula allots half of the funds according to a State's aggregate residential energy expenditure (relative to the total for all States), and half according to heating degree days squared, weighted by number of households below the BLS lower living standard. However, the allotment of any State is to be increased under an alternative allotment percentage by an amount necessary to provide at least $120 per year to each AFDC, SSI and food stamp household in the State. Further, no State would receive less than the lower of the amounts it would have received under either of two alternative formulas. Increases in allotments which result from either the minimum or from the alternative formulas would result in pro rata reductions in the allotments of other States, except that two additional authorizations of $25 million and $90 million are provided to meet the additional costs resulting from the application of the minimum benefit provision to certain States. If the amount appropriated for fiscal year 1981 is less than the $3 billion primary authorization and the amounts necessary under the separate $25 million and $90 million authorizations, then each State's allotment will be determined as if this sum had been appropriated and will be reduced on a pro rata basis as necessary.

The remaining five percent of the amount appropriated under the $3 billion authorization is reserved for the territories, the Community Service Administration's crisis intervention program ($100 million), and matching incentive grants to States for State initiatives under this program.

State plan requirements

Each State is required to submit an energy assistance plan which is subject to approval by the Secretary of Health, Education and Welfare. The following are among the provisions allowed or required under an approved State plan, except that the Secretary may waive any of these requirements if he finds that a waiver would promote the objectives of the program:

1. Residential energy assistance can be given directly to eligible households, in the form of either cash or coupons; to suppli-

ers of energy to these households, in either cash or State tax credits; and to operators of subsidized housing projects. Renters and owners are to be treated equitably.

2. Priority generally is to be given to the lowest-income households, to the aged, and disabled, and to those with the largest energy costs in relation to their income.

3. The amount of assistance can vary within the State according to such factors as type of fuel used and degree days in different locations.

4. Energy suppliers who participate in providing assistance have to agree to various conditions including notice and delay requirements before shutting off service to eligible households. These notice and delay requirements do not apply to small suppliers.

5. States are required to provide 50 percent of administrative cost from non-Federal sources. Total administrative costs, other than under unusual circumstances, are limited to 10 percent of program costs (i.e., 5 percent Federal and 5 percent non-Federal).

6. Plans are required to provide for referral, coordination, outreach, monitoring and auditing.

7. States are required to maintain existing levels of public assistance benefits, except that assistance under this program can replace any public assistance increase made solely to provide energy assistance.

8. Any assets test used for eligibility determination cannot count cars, personal belongings, and primary residences.

9. States can reserve up to three percent of funds for emergencies.

10. Grants specifically to meet the rising costs of cooling are allowed whenever the cooling is medically necessary.

Disregard provisions

Any assistance provided under this program may not be considered income or resources for any purpose under any Federal or State law, including any law relating to assistance or taxation. The Food Stamp Act is amended for fiscal year 1981 to provide that any increase in State public assistance intended primarily to meet the increased cost of home energy is not to be counted as income in the Food Stamp program.

E. OIL IMPORT RESTRICTIONS

(Sec. 402 of the Act)

Present Law

Section 232 of the Trade Expansion Act of 1962, as amended, authorizes the President to adjust imports of an article which is found to threaten to impair the national security. This authority to adjust imports includes the imposition of oil import license fees, as well as the use of import quotas.[1]

Under prior law, the Trade Expansion Act did not contain a specific procedure for Congressional review of Presidential actions taken to adjust imports.

Reasons for Change

Owing to the importance of all forms of energy to our economy, Congress believed that an orderly and specific procedure should be established for reviewing Presidential actions taken to adjust oil imports.

Explanation of Provision

The Act amends the Trade Expansion Act of 1962 by establishing a specific procedure for Congressional review of Presidential actions taken to adjust oil imports. Under the amendment, Presidential actions adjusting imports of petroleum or petroleum products would become ineffective upon an enactment of a joint "disapproval resolution." Any such resolution is to be considered under normal legislative procedures, rather than under those applicable to Trade Act matters generally, and is not to be amendable. The resolution could be vetoed by the President, but such a veto could be overridden by a two-thirds vote of both Houses of Congress.

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[1] *FEA* v. *Algonquin SNG, Inc.*, 426 U.S. 548 (1976).

F. OTHER INCOME TAX PROVISIONS

1. Repeal of Carryover Basis Provisions (Sec. 401 of the Act and sec. 1023 of the Code)

Prior Law

Under the Tax Reform Act of 1976, the basis of property passing or acquired from a decedent dying after December 31, 1976, was to be "carried over" from the decedent, with certain adjustments, to the estate or beneficiaries for purposes of determining gain or loss on sales and exchanges by the estate or beneficiaries. Under prior law, the basis of inherited property was generally stepped up or down to its value on the date of the decedent's death. The Revenue Act of 1978 postponed the effective date of the carryover basis provisions for 3 years. As postponed, the provisions of prior law applied to property passing or acquired from decedents dying after December 31, 1979.

Reasons for Change

A number of administrative problems concerning the carryover basis provisions have been brought to the attention of the Congress. Administrators of estates have testified that compliance with the carryover basis provisions has caused a significant increase in the time required to administer an estate and has resulted in raising the overall cost of administration. Congress believed that the carryover basis provisions are unduly complicated and should be repealed. However, Congress believed that an election to apply the carryover basis provisions should be permitted for the period these provisions would have been in effect but for the subsequent postponement under the Revenue Act of 1978. This election would cover situations where executors and beneficiaries have made sales, bequest funding, and asset retention decisions in reliance upon the carryover basis provisions.

Explanation of Provision

The Act repeals the carryover basis provisions. For property passing or acquired from a decedent (within the meaning of Code sec. 1014(b)), the basis of property will generally be its fair market value at the date of the decedent's death or at the applicable valuation date if the alternate valuation provision is elected for estate tax purposes.

With respect to property passing or acquired from decedents dying after 1976 and before November 7, 1978 (the date after the date of enactment of the Revenue Act of 1978), the carryover basis provisions may be elected by the executor of an estate. If elected, the basis of all carryover basis property considered to pass from the decedent, including jointly owned property passing by survivorship, would be deter-

mined under these provisions. The election is to be irrevocably made no later than 120 days after the date of enactment of the bill and in such manner as prescribed by the Secretary of the Treasury.

Effective Date

The amendments are to take effect as if included in the Tax Reform Act of 1976. Thus, the repeal applies to property passing or acquired from a decedent dying after December 31, 1976.

Revenue Effect

Repeal of carryover basis will reduce revenues by a negligible amount in fiscal year 1981, by $36 million in 1982, $95 million in 1983, $163 million in 1984 and $235 million in 1985.

2. Partial Exclusion of Dividends and Interest Received by Individuals (Sec. 404 of the Act and sec. 116 of the Code)

Prior Law

Under Code section 61, interest income received by individuals, in general, is subject to Federal income taxation. An exception to this rule applies to interest received on State and local government obligations.

In addition, under Code section 116, the first $100 of dividends received by an individual from domestic corporations is excludable from gross income. In the case of a husband and wife, each spouse is entitled to a separate exclusion of up to $100 for dividends received with respect to stock owned by that spouse.

Reasons for Change

In recent years, individual savings relative to disposable personal income have decreased markedly. This decrease has had an adverse effect throughout the economy, and as a result, less capital has been available for corporate investment in plant and equipment and for individuals seeking to purchase homes.

Congress decided that, in order to increase individual savings in an efficient manner, it could expand the dividend exclusion in prior law to include interest on certain types of debt instruments and increase the amount of such income eligible for the exclusion. However, to encourage further analysis of the appropriate tax treatment of dividend and interest income, Congress believed that the increase in the exclusion and the expansion to include interest income, as well as dividends, should be made temporary.

Explanation of Provision

The Act expands the present dividend exclusion to include certain kinds of interest and increases the maximum amount to $200 in the case of an individual. The Act also provides a $400 exclusion in the case of a joint return, regardless of whether the dividend is received by one or both spouses.

Interest eligible for the exclusion includes: (1) interest on deposits received from a bank; (2) interest (whether or not designated as interest) paid in respect of deposits, investment certificates, or withdrawable or repurchasable shares by a mutual savings bank, cooperative bank, domestic building and loan association, industrial loan association or bank, credit union, or other savings or thrift institution chartered and supervised under Federal or State law if the deposits or accounts of the institution are insured under Federal or State law,

or protected and guaranteed under State law; (3) interest on bonds, debentures, notes, certificates or other evidences of indebtedness of a domestic corporation which are in registered form; (4) interest on other evidences of indebtedness issued by a domestic corporation of a type offered by corporations to the public to the extent provided in regulations issued by the Secretary of the Treasury; (5) interest on obligations of the United States or a State or local government which is not already excluded from gross income; and (6) interest attributable to a participation share in a trust established and maintained by a corporation established pursuant to Federal law (for example, interest attributable to a participation share in a trust established and maintained by the Government National Mortgage Association).

In the case of distributions received by individuals from conduit type entities (such as trusts, regulated investment companies, and real estate investment trusts), the distributions generally qualify for the exclusion to the same extent that the gross income of the entity consists of eligible dividends or eligible interest.

In the case of a regulated investment company, conduit treatment is extended to qualifying dividends (as under prior law) and to qualifying interest. The amount of interest received by a regulated investment company that will be eligible for the exclusion when it is distributed to shareholders is the net amount of qualifying interest (i.e., qualifying interest less interest expense). If a regulated investment company has at least 75 percent of its gross income from either qualified dividends or from qualified interest, then the entire amount of the dividend (other than capital gain dividend) that it pays will be a qualified dividend in the hands of an individual shareholder. If neither qualifying dividends nor qualifying interest equals or exceeds 75 percent of the gross income, then the percentage of each dividend it pays that qualifies for the exclusion is the proportion of that dividend that the sum of the qualifying dividends and qualifying interest of the regulated investment company for the taxable year bears to the gross income of the regulated investment company for the taxable year. For this purpose, gross income and aggregate interest are to be reduced by any interest expense to the extent of any qualified interest. For example, if a regulated investment company has 40 percent of its gross income from qualified dividends and 40 percent of its gross income from qualified interest, then 80 percent of its dividend (other than its capital gain dividend) will be a qualified dividend in the hands of an individual shareholder.

In the case of a real estate investment trust, conduit treatment is extended to qualifying interest but not to dividends. If a real estate investment trust has at least 75 percent of its gross income from qualifying interest, then the entire amount of a noncapital gain dividend from the real estate investment trust will be a qualified dividend in the hand of an individual shareholder. If qualifying interest does not equal or exceed 75 percent of the gross income, then the percentage of its noncapital gain dividend that qualifies for the exclusion is the proportion of that dividend that the qualifying interest of the real estate investment trust for the taxable years bears to the gross income of the real estate investment trust for the taxable year. As in the case of regulated investment companies, only the net amount of the qualifying interest (i.e., qualifying interest less interest expense) is eligible for the exclu-

sion. However, in the case of a real estate investment trust, the amount of qualified interest is not reduced by any interest paid by the real estate investment trust on mortgages on real property that is owned by the real estate investment trust. In addition, gross income is to be reduced by the net capital gain and by any taxes imposed on income from foreclosure property (section 857(b)(4)), on the failure to meet certain requirements (section 857(b)(5)), or on income from prohibited transactions (section 857(b)(6)). The amount that qualifies for the exclusion shall not exceed the amount designated by the real estate investment trust in a notice to its shareholders sent within 45 days after the close of its taxable year.

In addition, special rules are provided in regard to interest expenses incurred in order to purchase or to carry obligations or shares or to make deposits or other investments with respect to which the interest would be excludable from gross income under this provision.

Effective Date

The exclusion applies to taxable years beginning after December 31, 1980 and before January 1, 1983.

Revenue Effect

The revenue loss is expected to be $0.3 billion in fiscal year 1981, $2.3 billion in 1982 and $1.7 billion in 1983.

3. Qualified Liquidations of LIFO Inventories (Sec. 403(a) of the Act and sec. 473 of the Code)

Prior Law

Under prior law, a taxpayer who liquidates part of all of his inventory (i.e., his beginning inventory is greater than his ending inventory) in the ordinary course of his trade or business recognized the gain or loss realized as a result of the liquidation. The taxpayer recognized this gain or less even if the liquidation of the inventory is due to circumstances beyond his control, e.g., reduced supply due to government regulation or the interruption of foreign trade. In the case of inventories accounted for on the last-in, first-out ("LIFO") basis, a significant portion of the gain on such liquidation was usually attributable to the excess of the replacement cost of such inventory over its LIFO basis (referred to as "LIFO inventory profit").

Reasons for Change

Due to the current possibilities for disruption of trade in the international energy market, Congress felt that taxpayers who have a temporary liquidation of their LIFO inventory of energy supplies because of a major foreign trade interruption or a Department of Energy regulation or request, should be given relief from the tax attributable to the LIFO inventory profit. Similarly, Congress felt that taxpayers who experience a temporary liquidation of their LIFO inventories of other property due to major foreign trade interruption should also be given relief from taxes attributable to LIFO inventory profits.

Explanation of Provision

In certain narrowly defined circumstances, the Act allows a taxpayer to claim a refund for taxes paid on LIFO inventory profits resulting from the liquidation of LIFO inventories, if the taxpayer purchases replacement inventory within a defined replacement period. A taxpayer can elect to have the provisions of this section apply if there is a liquidation of his LIFO inventory for a taxable year (referred to as the "liquidation year") and he establishes to the satisfaction of the Secretary that the liquidation is a qualified liquidation. A qualified liquidation is defined as a decrease in a taxpayer's closing LIFO inventory for a liquidation year over his opening LIFO inventory for that year, but only if the taxpayer establishes to the satisfaction of the Secretary that the decrease is directly and primarily attributable to a qualified inventory interruption. A qualified inventory interruption is defined as any Department of Energy regulation or request made with respect to energy supplies or any embargo, international boycott, or other

major foreign trade interruption, with respect to either of which the Secretary publishes a notice in the Federal Register designating those situations to which the provisions of this section will be available. The notice will be published in the Federal Register if the Secretary determines, after consultation with the appropriate Federal officers, that such regulation, request or interruption has made the replacement of any class of goods for any class of taxpayers difficult or impossible in the liquidation year, and the application of this provision to that class of goods and taxpayers is necessary to carry out the purposes of this section.

If a qualifying taxpayer replaces part or all of the liquidated LIFO inventory in a replacement year, then the taxpayer's taxable income for the liquidation year is (i) decreased by the excess of the cost of the replacement inventory over the LIFO basis of the liquidated inventory which it replaced, or (ii) increased by the excess of the LIFO basis of the liquidated inventory which is replaced over the cost of the replacement inventory. A replacement year is defined as the earlier of the three taxable years following the liquidation year or any taxable year ending within such earlier period as the Secretary may prescribe. (Any period specified by the Secretary may be modified by the Secretary by publication of a notice in the Federal Register.) However, a replacement year does not include a taxable year after the taxable year in which replacement of the liquidated inventory is completed.

A taxpayer is considered to have acquired a replacement for the liquidated LIFO inventory if the taxpayer's closing LIFO inventory (with respect to the liquidated goods) for any replacement year reflects an increase over the opening inventory for such year. The replacement inventory is considered, in the order of its acquisition, as replacing the most recently liquidated inventory (whether or not the liquidation is a qualified liquidation) not previously replaced. If the replacement inventory replaces LIFO inventory which was subject to a qualified liquidation, it is to be taken into purchases and included in the closing inventory for the replacement year at the LIFO basis of the inventory which it replaced.

If an adjustment in a taxpayer's taxable income is made for any liquidation year as a result of the replacement of LIFO inventories under this section, the tax imposed for the liquidation year and any other taxable year would be redetermined to take into account that adjustment. Any increase or decrease in the amount of the tax resulting from the redetermination would be assessed as a deficiency or allowed as a credit or refund (as the case may be). Solely for purposes of determining interest on overpayments or underpayments of tax attributable to adjustments made under this provision, the overpayment or underpayment shall be treated as arising in the replacement year.

The assessment of a deficiency or the allowance of a credit or refund attributable to the adjustment may, if otherwise prevented by the operation of any law or rule of law (other than section 7122), be made within the time allowed for the assessment of a deficiency or the allowance of a credit or refund (as the case may be) with respect to the replacement year in which the adjustment arose.

An election to have the provisions of this section apply would be made in the manner and form, and at the time, prescribed by the Secretary in regulations. The election is irrevocable and binding for the liquidation year and for all determinations made for taxable years prior and subsequent to the liquidation year insofar as such determinations are affected by the adjustments made under this section.

Where there is more than one reduction in a taxpayer's LIFO inventory and these reductions are due to different causes, the reduction in the closing inventory will be presumed to occur first as a result of qualified liquidations, if any, under this provision. For example, if a taxpayer's closing inventory has been reduced by a total of 300 units and the taxpayer had a fire during the year which destroyed 275 units and a qualified liquidation which accounted for 225 units, the reduction in the closing inventory will be attributable to the 225 units from the qualified liquidation and the 75 units from the fire.

Effective Date

This provision is effective for taxable years ending after October 31, 1979.

Revenue Effect

The revenue loss is expected to be $85 million in each of the fiscal years 1982 and 1983 and $80 million in 1984. These losses are attributable to involuntary liquidations assumed to occur in calendar year 1980. (These estimates were based on the assumption that the Secretary will invoke this provision for disruptions of oil shipments during 1980.)

4. Recognition of Gain of Certain Dispositions of LIFO Inventories (Sec. 403(b) of the Act and secs. 336 and 337 of the Code)

Prior Law

Under prior law, a liquidating corporation did not recognize any gain or loss on the transfer of its inventory to its shareholders as part of the liquidation. Similarly, a corporation which sells its assets during a 12-month liquidation (section 337) did not recognize any gain or loss on the bulk sale of its inventory. In either situation, if the liquidating corporation accounts for its inventory on the last-in, first-out ("LIFO") method of accounting for inventories, any gain attributable to the excess (referred to as the "LIFO recapture amount") of the adjusted basis of the inventory under the first-in, first-out ("FIFO") method of accounting for inventories over its LIFO adjusted basis was not subject to corporate tax. (On nonliquidating distributions of LIFO inventories, this amount was taxed at the corporate level (sec. 311(b)). However, if a subsidiary corporation liquidates into a parent corporation and the adjusted basis of the subsidiary's assets carry over to the parent corporation, the LIFO recapture amount was subject to corporate taxation when the inventory was subsequently disposed of by the parent corporation in a taxable sale or exchange.

Reasons for Change

Congress believed that the LIFO recapture amount of a corporation's inventory should be subject to tax upon a corporate liquidation unless the LIFO recapture amount is preserved in the corporation's inventory by virtue of a carry-over basis. Otherwise, corporations could convert the tax deferral provided by LIFO into an outright exclusion from tax.

Explanation of Provision

Under the Act, a corporation which distributes its LIFO inventory in a partial or complete liquidation of the corporation must recognize the inventory's LIFO recapture amount as ordinary income. Also, a corporation that sells its LIFO inventory in the course of a 12-month liquidation (section 337) must recognize the inventory's LIFO recapture amount as ordinary income. The provision does not require the recognition of the LIFO recapture amount on corporate liquidations where the adjusted basis of the LIFO inventory in the hands of the acquiring corporation is carried over from the liquidating corporation.

Effective Date

This provision applies to distributions and dispositions which are made pursuant to plans of liquidation adopted after December 31, 1981. The effective date was postponed to allow time for Congressional hearings on this provision and for transactions in the planning stage to be completed. During this time period it was intended that there would be no change in the present law treatment of the LIFO recapture amount with respect to corporate liquidations and sales pursuant to 12-month corporate liquidations.

Revenue Effect

There is a revenue gain for fiscal year 1982 of $112 million and a revenue gain for calendar year 1982 of $250 million. In each fiscal and calendar year thereafter, there will be a revenue gain of $250 million. (These estimates were based on information obtained from a selected number of cases known to the Treasury and the figures are intended to provide representative averages during the forecast period.)